

## **CONSTRUCTION PERMIT**

**PERMIT NUMBER: CPM02-0006**

**PREVENTION OF SIGNIFICANT DETERIORATION (PSD)  
PERMIT TO MODIFY AN  
AIR CONTAMINANT SOURCE  
IS HEREBY ISSUED TO:**

Archer Daniels Midland Company (ADM)  
3000 East 8<sup>th</sup> Street  
Columbus, Nebraska 68601-9073

**FOR THE SPECIFIC MODIFICATION OF:**

A Wet Corn Milling and Ethanol Production Facility

**TO BE LOCATED AT**

3000 East 8th Street  
Columbus, Nebraska 68601-9073

Pursuant to Chapter 14 of the Nebraska Air Quality Regulations, the public has been notified by prominent advertisement of this proposed modification of an air contaminant source and the thirty (30) day period allowed for comments has elapsed. This Construction Permit approves the proposed construction of two new coal-fired boilers and support equipment, one new natural gas-fired boiler, and modification of the existing gluten flash dryer #2 and the fluid bed germ dryer. In addition, this Construction Permit approves the construction of new control equipment for several existing sources, places new and/or revised emission limits on existing equipment, and supersedes all previous construction permits issued for this source. The operations covered by this permit consists of a facility that manufactures ethanol (primary SIC 2046, secondary SIC 2869), starches, high fructose corn syrup, and animal feed products utilizing the wet milling process.

This permit may contain abbreviations and symbols of units of measure, which are defined in 40 CFR Part 60.3. Other abbreviations may include, but are not limited to, the following: Ammonia (NH<sub>3</sub>), Best Available Control Technology (BACT), Boiler Operating Day (BOD), Circulating Fluidized Bed Boiler (CFB Boiler), Carbon Monoxide (CO), Chemical Abstract Service Number (CAS #), Code of Federal Regulations (CFR), Compilation of Air Pollutant Emission Factors, Volume I, Stationary Point and Area Sources (AP-42), Construction Permit (CP), Continuous Emissions Monitor System (CEMs), Continuous Opacity Monitoring System (COMS), Factor Information and Retrieval System (FIRE), Hazardous Air Pollutant (HAP), Hydrochloric acid (HCl), Hydrofluoric acid (HF), Hydrogen Sulfide (H<sub>2</sub>S), Lead Compounds (Pb), Lowest Achievable Emission Rate (LAER), Maximum Achievable Control Technology (MACT), Mechanical Recompression (MR), Mercury Compounds (Hg), Million British Thermal Units (MMBtu), National Ambient Air Quality Standards (NAAQS), New Source Performance

Standards (NSPS), Nitrogen Oxides (NO<sub>x</sub>), Office of Management and Budget (OMB), Operating Permit (OP), Particulate Matter (PM), Particulate Matter less than or equal to 10 micrometers (PM<sub>10</sub>), Parts per million (ppm), Parts per million dry volume (ppmdv) Pounds per Hour (lbs/hr), Prevention of Significant Deterioration (PSD), Rotary Vacuum Filter (RVF), Selective Non-catalytic Reduction (SNCR), Stack/Vent (SV), Sulfur Dioxide (SO<sub>2</sub>), Sulfuric Acid (H<sub>2</sub>SO<sub>4</sub>), Total Dissolved Solids (TDS), Total Reduced Sulfur (TRS), Total Selected Metal (TSM), Volatile Organic Compounds (VOC).

This permit is issued with the following conditions under the authority of Title 129 - Nebraska Air Quality Regulations as amended March 14, 2006:

### **General Conditions**

- I. This permit is not transferable to another source or location. (Title 129, Chapter 17)
- II. Holding of this permit does not relieve the owner/operator of the source from the responsibility to comply with all applicable portions of the Nebraska Air Quality Regulations and any other requirements under local, State, or Federal law. Any permit noncompliance shall constitute a violation of the Nebraska Environmental Protection Act and the Federal Clean Air Act, and is grounds for enforcement action or permit revocation. {Title 129, Chapter 41 & Chapter 17, Section 011}
- III. Application for review of plans or advice furnished by the Director will not relieve the source of legal compliance with any provision of these regulations, or prevent the Director from enforcing or implementing any provision of these regulations. {Title 129, Chapter 37}
- IV. Any applicant who fails to submit any relevant facts or who has submitted incorrect information in a permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. If the source wishes to make changes at the facility that will result in change(s) to values, specifications, and/or locations of emission points that were indicated in the permit application (or other supplemental information provided by the applicant and reviewed by the Department in issuance of this permit), the source must receive approval from the Department before the change(s) can be made. In addition, any modification which may result in an adverse change to the air quality impacts predicted by atmospheric dispersion modeling (such as changes in stack parameters or increases in emission rates, potential emissions, or actual emissions) shall have prior approval from the Department. The source shall provide all necessary information to verify that there are no substantive changes affecting the basis upon which this permit was issued. Information may include, but not be limited to, additional engineering, modeling and ambient air quality studies. {Title 129, Chapter 17, Section 006, 007, & 008}
- V. Approval to construct, reconstruct and/or modify the source will become invalid if a continuous program of construction is not commenced within 18 months after the date of issuance of the construction permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable period of time. {Title 129, Chapter 17, Section 012}
- VI. The owner/operator of the source shall provide a notification to the Department of the date of construction, reconstruction or modification commenced, postmarked no later than 30 days after such date, and of the actual date of initial startup of operation, postmarked within 15 days after such date. {Title 129, Chapter 17, Section 012}

- VII. The permittee shall allow the Department, EPA or an authorized representative, upon presentation of credentials to: {Neb. Rev. Statute §81-1504}
- (A) Enter upon the permittee's premises at reasonable times where a source subject to this permit is located, emissions-related activity is conducted or records are kept, for the purpose of ensuring compliance with the permit or applicable requirements;
  - (B) Have access to and copy, at reasonable times, any records, for the purpose of ensuring compliance with the permit or applicable requirements;
  - (C) Inspect at reasonable times any facilities, pollution control equipment, including monitoring and air pollution control equipment, practices, or operations, for the purpose of ensuring compliance with the permit or applicable requirements;
  - (D) Sample or monitor at reasonable times substances or parameters for the purpose of ensuring compliance with the permit or applicable requirements.
- VIII. When requested by the Department, the permittee shall submit completed emission inventory forms for the preceding year to the Department by March 31 of each year. {Title 129, Chapter 6}
- IX. Open fires are prohibited except as allowed by Title 129, Chapter 30.
- X. Particulate Matter – General Requirements: {Title 129, Chapter 32}
- (A) The permittee shall not cause or permit the handling, transporting or storage of any material in a manner, which allows particulate matter to become airborne in such quantities and concentrations that it remains visible in the ambient air beyond the property line.
  - (B) The permittee shall not cause or permit the construction, use, repair or demolition of a building, its appurtenances, a road, a driveway, or an open area without applying all reasonable measures to prevent particulate matter from becoming airborne and remaining visible beyond the property line. Such measures include, but not limited to, paving or frequent cleaning of roads, driveways and parking lots; application of dust-free surfaces; application of water; and planting and maintenance of vegetative ground cover.
- XI. If and when the Director declares an air pollution episode as defined in Title 129, Chapter 38, Sections 003.01B, 003.01C, or 003.01D, the source shall immediately take all required actions listed in Title 129, Appendix I until the Director declares the air pollution episode terminated.
- XII. This permit may be revised (reopened and reissued) or revoked for cause in accordance with Title 129 and Title 115, Rules of Practice and Procedure. Conditions under which this permit will be revised or revoked for cause, include but are not limited to: {Title 129, Chapter 15, Section 006}
- (A) A determination by the Director, or the Administrator of EPA that:
    - (1) the permit must be revised to ensure compliance with the applicable requirements;

- (2) the permit contains a material mistake or that inaccurate statements were made in the emissions standards or other terms or conditions of the permit.
- (B) The existence at the facility of unresolved noncompliance with applicable requirements or a term or condition of the permit, and refusal of the permittee to agree to an enforceable schedule of compliance to resolve the noncompliance;
- (C) The submittal by the permittee of false, incomplete, or misleading information to the Department or EPA;
- (D) A determination by the Director that the permitted facility or activity endangers human health or the environment and that the danger cannot be removed by a revision of the permit; or
- (E) The failure of the permittee to pay a penalty owed pursuant to court order, stipulation and agreement, or order issued by the Administrator of the EPA.

### Specific Conditions

XIII. Specific terms and conditions of this permit:

- (A) The following conditions apply to: GRAIN HANDLING AND PROCESSING OPERATIONS:
- (1) The grain handling and processing equipment shall consist of the emission points and control devices presented in Table 1:

**Table 1. Grain Handling and Processing Equipment**

<b>Emission Unit ID</b>	<b>SV #</b>	<b>Equipment Description</b>	<b>Add-on control device</b>
EU1-1	1	Corn Receiving (East Truck Unloading Pits #1 and #2)	Baghouse
EU1-2	2	Corn Receiving (West Truck Unloading Pits #3 and #4)	Baghouse
EU2-3	3	Corn Cleaner/Fines Bin	Baghouse
EU2-4	4	Corn Cleaner	Baghouse
EU2-42	42	Corn Fines Transfer	Baghouse
EU1-54	54	Corn Silo #1	Baghouse
EU1-55	55	Corn Silo #2	Baghouse
EU1-56	56	Corn Silo #3	Baghouse
EU1-57	57	Corn Silo #4	Baghouse
EU1-58	58	Corn Silo #5	Baghouse
EU1-59	59	Corn Silo #6	Baghouse
EU1-60	60	Corn Silo #7	Baghouse
EU1-61	61	Corn Silo #8	Baghouse
EU14-71	71	Rail Corn Receiving, Storage, and Handling	Baghouse
EU14-72	72	Corn Storage Bin 9A	Baghouse
EU14-73	73	Corn Storage Bin 9B	Baghouse

<b>Emission Unit ID</b>	<b>SV #</b>	<b>Equipment Description</b>	<b>Add-on control device</b>
EU14-74	74	Corn Storage Bin 10A	Baghouse
EU14-75	75	Corn Storage Bin 10B	Baghouse
EU14-76	76	Corn Storage Bin 11A	Baghouse
EU14-77	77	Corn Storage Bin 11B	Baghouse
EU14-78	78	Corn Storage Bin 12A	Baghouse
EU14-79	79	Corn Storage Bin 12B	Baghouse
EU14-80	80	Corn Storage Bin 13A	Baghouse
EU14-81	81	Corn Storage Bin 13B	Baghouse
EU14-82	82	Corn Storage Bin 14A	Baghouse
EU14-83	83	Corn Storage Bin 14B	Baghouse
EU14-84	84	Corn Storage Bin 15A	Baghouse
EU14-85	85	Corn Storage Bin 15B	Baghouse
EU14-86	86	Corn Storage Bin 16A	Baghouse
EU14-87	87	Corn Storage Bin 16B	Baghouse
EU14-88	88	Corn Storage Bin 17A	Baghouse
EU14-89	89	Corn Storage Bin 17B	Baghouse
EU14-105	105	Rail Corn Silo #1	Baghouse
EU14-106	106	Rail Corn Silo #2	Baghouse

- (2) The grain handling and processing equipment shall be properly installed, operated and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the grain handling and processing equipment shall be kept on site and readily available to Department representatives. {Title 129, Chapters 19 and 20}
- (3) The operation of each dry dust collector (baghouse) shall be in accordance with the following requirements: {Title 129, Chapters 19 and 20}
  - (a) The dry dust collectors shall be operated whenever the associated emission units are in operation.
  - (b) The dry dust collectors shall be properly installed, operated and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the dry dust collectors shall be kept on site and readily available to Department representatives.
  - (c) The dry dust collectors for EU1-1, EU1-2, EU2-3, EU2-4, EU2-42, EU14-71, EU14-105, and EU14-106 shall be equipped with an operational pressure differential indicator. The pressure differential indicator readings shall be recorded at least once each day that the associated dry dust collector is operating. The pressure indicator shall be properly installed, operated, calibrated, and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the pressure differential indicator shall be kept on site and readily available to Department representatives.

- (d) Dry dust collector filter bags/cartridges are to be inspected and/or replaced according to the operation and maintenance manual or more frequently as indicated by pressure differential indicator readings or other indication of unit failure.
  - (e) Routine observations (at least once each day during daylight hours of dry dust collector operation) shall be conducted for dry dust collectors stacks SV# 1 – 4, 42, 71, 105 and 106 to determine whether there are visible emissions from the stack, leaks, noise, atypical pressure differential readings, or other indications, which may necessitate corrective action. Corrective action shall be taken immediately if necessary. For the bin vent dust collector stacks (SV# 54-61 and 72-89) routine observations (at least once weekly) shall be conducted and recorded to determine whether there are excessive visible emissions from the vents, or other indications of poor performance (e.g. material build-up on vents) requiring corrective action. Corrective action shall be taken immediately if necessary.
  - (f) Collected waste material from the dry dust collectors shall be handled, transported, and stored in a manner that ensures compliance with Condition X.
  - (g) The source shall maintain on-site an inventory of spare bags/cartridges of each type used to ensure rapid replacement in the event of bag/cartridge failure.
- (4) The PM and PM<sub>10</sub> emissions from the grain handling and processing baghouses shall not exceed the emission limits in Table 2 (3-hour or test method average). {Title 129, Chapters 4, 19, and 20}

**Table 2. Grain Handling and Processing Emission Limits**

SV #	Equipment Description	PM/PM <sub>10</sub> limitation (lbs/hr)
1	Corn Receiving (East Truck Unloading Pits #1 and #2)	0.52
2	Corn Receiving (West Truck Unloading Pits #3 and #4)	0.52
3	Corn Cleaner/Fines Bin	0.10
4	Corn Cleaner	0.52
42	Corn Fines Transfer	0.04
54	Corn Silo #1	0.16
55	Corn Silo #2	0.16
56	Corn Silo #3	0.16
57	Corn Silo #4	0.21
58	Corn Silo #5	0.21
59	Corn Silo #6	0.21
60	Corn Silo #7	0.21
61	Corn Silo #8	0.21
71	Rail Corn Receiving, Storage, and Handling	0.82
72	Corn Storage Bin 9A	0.02

SV #	Equipment Description	PM/PM <sub>10</sub> limitation (lbs/hr)
73	Corn Storage Bin 9B	0.02
74	Corn Storage Bin 10A	0.02
75	Corn Storage Bin 10B	0.02
76	Corn Storage Bin 11A	0.02
77	Corn Storage Bin 11B	0.02
78	Corn Storage Bin 12A	0.02
79	Corn Storage Bin 12B	0.02
80	Corn Storage Bin 13A	0.02
81	Corn Storage Bin 13B	0.02
82	Corn Storage Bin 14A	0.02
83	Corn Storage Bin 14B	0.02
84	Corn Storage Bin 15A	0.02
85	Corn Storage Bin 15B	0.02
86	Corn Storage Bin 16A	0.02
87	Corn Storage Bin 16B	0.02
88	Corn Storage Bin 17A	0.02
89	Corn Storage Bin 17B	0.02
105	Rail Corn Silo #1	0.39
106	Rail Corn Silo #2	0.90

- (5) The New Source Performance Standards for Grain Elevators, Subpart DD {Title 129, Chapter 18, Section 001.19} apply to the rail corn receiving, storage, and handling equipment (EU14-71) and the corn cleaner (EU2-4). These requirements include but are not limited to the following: {40 CFR, Part 60, Subpart DD}
- (a) Any grain handling operations other than grain dryers shall not emit particulate matter in excess of 0.023 g/dscm (0.01 gr/dscf) and shall not exhibit greater than 0% opacity.
  - (b) Fugitive particulate matter emissions from railcar unloading shall not exhibit greater than 5% opacity.
  - (c) Testing to determine the compliance with the limitations in Conditions XIII.(A)(5)(a) and (b) shall be in accordance with 40 CFR 60.303.
- (6) In order to demonstrate compliance with Condition XIII.(A)(4), the source shall conduct performance tests as specified in Table 3. The performance test shall be conducted in accordance with Condition XIII.(V). {Title 129, Chapter 34}

**Table 3. Grain Handling and Processing Test Requirements**

SV #	Equipment Description	PM/PM <sub>10</sub> Test Required
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SV #	Equipment Description	PM/PM <sub>10</sub> Test Required
1	Corn Receiving (East Truck Unloading Pits #1 and #2)	No
2	Corn Receiving (West Truck Unloading Pits #3 and #4)	No
3	Corn Cleaner/Fines Bin	Yes <sup>1</sup>
4	Corn Cleaner	No
42	Corn Fines Transfer	Yes <sup>1</sup>
54-56	Corn Silo #1-3	No
57-61	Corn Silo #4-8	No
71	Rail Corn Receiving, Storage, and Handling	No
72-89	Corn Storage Bins 9A, 9B, 10A, 10B, 11A, 11B, 12A, 12B, 13A, 13B, 14A, 14B, 15A, 15B, 16A, 16B, 17A, and 17B	No
105	Rail Corn Silo #1	Yes <sup>2</sup>
106	Rail Corn Silo #2	Yes <sup>2</sup>

<sup>1</sup>Initial performance testing is required for SV#3 and 42; however, only one of the two sources must be tested if the first performance test demonstrates compliance. If the test indicates non-compliance, the other emission point shall be tested to independently verify compliance.

<sup>2</sup>Initial performance testing is required for SV#105 and 106; however, only one of the two sources must be tested if the first performance test demonstrates compliance. If the test indicates non-compliance, the other emission point shall be tested to independently verify compliance.

- (7) Fugitive emissions from the railcar unloading stations shall be further reduced by choke loading the receiving pits. Additionally, the railcar unloading stations shall be partially enclosed by a roof and two (2) sidewalls. {Title 129, Chapters 4 and 19}

(B) The following conditions apply to MILLHOUSE/FEEDHOUSE OPERATIONS:

- (1) A ventilation system must be used to aspirate the wet corn milling and feedhouse equipment (EU3-5), the stillage/steepwater evaporators (EU12-69 and EU12-70) and the gluten RVFs (EU6-66, EU6-67, and EU6-68). The emissions captured by the ventilation system shall be controlled by the millhouse scrubber system, consisting of two wet scrubbers that vent through a common stack (SV-5). {Title 129, Chapters 4 and 19}
- (2) The operation of the millhouse scrubber system shall be in accordance with the following requirements: {Title 129, Chapters 19 and 27}
  - (a) Both scrubbers shall be operated at all times when the associated emission units are in operation.
  - (b) The scrubbers shall be properly designed, installed, operated and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the scrubbers shall be kept on site and readily available to Department representatives.



- (c) The scrubbers shall be equipped with indicators of scrubbing liquid flow rate, pH, and pressure differential. Operating parameter readings shall be recorded at least once each day the scrubbers are in operation. The indicators shall be properly installed, operated, calibrated, and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the operating parameter indicators shall be kept on site and readily available to Department representatives.
  - (d) Routine observations (at least once each day of scrubber operation) shall be conducted to determine whether there are leaks, noise, atypical operating parameters (e.g., scrubbing liquid flow rate), or other indications that may necessitate corrective action.
- (3) The emissions from the millhouse scrubber system stack (SV-5) shall not exceed the following emission limits (3-hour or test method average). {Title 129, Chapters 4 and 19}
- (a) 3.89 pounds per hour PM/PM<sub>10</sub>.
  - (b) 6.75 pounds per hour SO<sub>2</sub>.
- (4) VOC emissions entering the millhouse scrubber system shall be reduced by 95%, or to a level of 20 ppmvd. {Title 129, Chapter 27 and Consent Decree (United States v. ADM, No. 03-CV-2066 (C.D. Illinois))}
- (5) In order to demonstrate compliance with Conditions XIII.(B)(3) and (B)(4) and to verify assumptions used in the permit application, the source shall conduct a performance test for PM, PM<sub>10</sub>, SO<sub>2</sub>, HAPs, and VOC, on stack SV-5. The performance test shall determine the VOC control efficiency of the millhouse scrubber system. The performance test shall be conducted in accordance with Condition XIII.(V) and shall include speciation and quantification of the HAP composition of the emissions. VOC emissions shall be expressed as total mass of VOC. {Title 129, Chapter 34}

(C) The following conditions apply to: FIBER DEWATERING

- (1) The emissions from the fiber dewatering vent (SV-43) shall not exceed the following emission limits (3-hour or test method average). {Title 129, Chapters 4 and 19}
- (a) 0.627 pounds per hour PM/PM<sub>10</sub>
  - (b) 4.06 pounds per hour SO<sub>2</sub>
  - (c) 1.52 pounds per hour VOC
- (2) In order to demonstrate compliance with Condition XIII.(C)(1) and to verify assumptions used in the permit application, the source shall conduct a performance test for PM, PM<sub>10</sub>, SO<sub>2</sub>, VOC, and HAPs on vent SV-43. The

performance test shall be conducted in accordance with Condition XIII.(V) and shall include speciation and quantification of the HAP composition of the emissions. VOC emissions shall be expressed as total mass of VOC. {Title 129, Chapter 34}

- (3) The dewatering equipment shall be properly installed, operated and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the dewatering equipment shall be kept on site and readily available to Department representatives.
- (D) The following conditions apply to: PRODUCT DRYING OPERATIONS (GERM, GLUTEN, STARCH):
  - (1) The product drying equipment shall consist of the emission points and control devices presented in Table 4: {Title 129, Chapters 19, and 27}

**Table 4. Product Drying Equipment**

<b>Emission Unit ID</b>	<b>SV #</b>	<b>Equipment Description</b>	<b>Dryer Heat Input (MMBtu/hr)</b>	<b>Add-on control device</b>
EU4-6	6	Starch Dryer # 1	NA – steam heated	Wet Scrubber
EU5-7A, EU5-7B, EU5-7C	7	Germ Dryers # 1-3	NA – steam heated	Wet Scrubber
EU5-8	8	Fluidized Bed Germ Dryer #1	55	Wet Scrubber, Low-NO <sub>x</sub> burner
EU6-16	16	Gluten Flash Dryer # 1	55	Wet Scrubber, Low-NO <sub>x</sub> burner
EU6-18	18	Gluten Flash Dryer # 2	65	Wet Scrubber, Low-NO <sub>x</sub> burner
EU4-45	45	Starch Dryer # 2	NA – steam heated	Wet Scrubber

- (2) The Gluten Flash Dryer # 1 shall only combust natural gas or natural gas combined with biogas from the wastewater treatment plant. The Gluten Flash Dryer # 2 and the Fluidized Bed Germ Dryer #1 shall burn natural gas only. {Title 129, Chapters 4 & 19}
- (3) The product drying equipment shall be properly installed, operated and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the product drying equipment shall be kept on site and readily available to Department representatives. {Title 129, Chapters 4 and 19}
- (4) Emissions from the product drying operations shall not exceed the emission limits in Table 5 (3-hour or test method average). {Title 129, Chapters 4, 19, and 27}

**Table 5. Product Drying Emission Limits**

SV #	Equipment Description	PM limitation (lb/hr)	PM <sub>10</sub> limitation (lb/hr)	NO <sub>x</sub> limitation (lb/hr)	SO <sub>2</sub> limitation (lb/hr)	CO limitation (lb/hr)	VOC limitation (lb/hr)
6	Starch Dryer # 1	3.03	3.03				
7	Germ Dryer #1-3	7.81	3.82		8.5		95% control efficiency or 20 ppmvd <sup>2</sup>
8	Fluidized Bed Germ Dryer #1	3.0	3.0	3.3	0.51	4.02	1.5
16	Gluten Flash Dryer # 1	3.34 <sup>1</sup>	8.0	4.35	6.6	15.2	22.8
18	Gluten Flash Dryer # 2	9.85	4.5	3.9	2.4	4.74	22.2
45	Starch Dryer # 2	3.03	3.03				

<sup>1</sup> Filterable only.

<sup>2</sup> Consent Decree (United States v. ADM, No. 03-CV-2066 (C.D. Illinois)).

- (5) The operation of each scrubber identified in Condition XIII.(D)(1) shall be in accordance with the following requirements: {Title 129, Chapters 19 and 27}
- (a) The scrubbers shall be operated at all times when the associated emission units are in operation.
  - (b) The scrubbers shall be properly designed, installed, operated and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the scrubbers shall be kept on site and readily available to Department representatives.
  - (c) The scrubbers shall be equipped with indicators of scrubbing liquid flow rate, pH (except the Starch Dryer scrubbers), and scrubber pressure differential. Operating parameter readings shall be recorded at least once each day the scrubbers are in operation. The indicators shall be properly installed, operated, calibrated, and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the operating parameter indicators shall be kept on site and readily available to Department representatives.
  - (d) Routine observations (at least once each day of scrubber operation) shall be conducted to determine whether there are leaks, noise, atypical operating parameters (e.g., scrubbing liquid flow rate), or other indications that may necessitate corrective action.
- (6) In order to demonstrate compliance with Condition XIII.(D)(4), the source shall conduct performance tests as specified in Table 6. The performance test shall be conducted in accordance with Condition XIII.(V) and shall include speciation and quantification of the HAP composition of the emissions. VOC emissions shall be expressed as total mass of VOC. {Title 129, Chapter 34}

**Table 6. Product Drying Test Requirements**

<b>SV #</b>	<b>Equipment Description</b>	<b>PM Test Required</b>	<b>PM<sub>10</sub> Test Required</b>	<b>NO<sub>x</sub> Test Required</b>	<b>SO<sub>2</sub> Test Required</b>	<b>CO Test Required</b>	<b>VOC/HAP Test Required</b>
6	Starch Dryer # 1	No	No	No	No	No	No
7	Germ Dryer #1, 2, and 3	Yes	Yes	No	Yes	No	Yes
8	Fluidized Bed Germ Dryer #1	Yes	Yes	Yes	Yes	Yes	Yes
16	Gluten Flash Dryer # 1	Yes	Yes	Yes	Yes	Yes	Yes
18	Gluten Flash Dryer # 2	Yes	Yes	Yes	Yes	Yes	Yes
45	Starch Dryer # 2	No	No	No	No	No	No

(E) The following conditions apply to: GERM, GLUTEN, AND STARCH COOLING AND STORAGE OPERATIONS:

- (1) The germ and gluten cooling and storage and starch storage equipment consists of the emission points and control devices presented in Table 7: {Title 129, Chapter 19}

**Table 7. Germ, Gluten, and Starch Cooling and Storage Equipment**

<b>Emission Unit ID</b>	<b>SV #</b>	<b>Equipment Description</b>	<b>Add-on control device</b>
EU5-9A	9	Germ Cooler # 1	Baghouse
EU5-9B		Germ Cooler # 2	Baghouse
EU5-9C		Germ Cooler # 3	Baghouse
EU5-12	12	Germ Cooler # 4	Baghouse
EU6-17	17	Gluten Cooler # 1	Baghouse
EU6-19	19	Gluten Cooler # 2	Baghouse
EU4-20	20	Starch Storage Bin # 11	Baghouse
EU4-21	21	Starch Storage Bin # 12	Baghouse
EU4-22	22	Starch Storage Bin # 9	Baghouse
EU4-23	23	Starch Storage Bin # 10	Baghouse
EU5-24	24	Gluten Storage Bin # 7	Baghouse
EU5-25	25	Gluten Storage Bin # 8	Baghouse
EU5-26	26	Gluten Storage Bin # 5	Baghouse
EU5-27	27	Gluten Storage Bin # 6	Baghouse
EU6-28	28	Germ Storage Bin # 3	Baghouse
EU6-29	29	Germ Storage Bin # 4	Baghouse
EU6-30	30	Germ Storage Bin # 1	Baghouse
EU6-31	31	Germ Storage Bin # 2	Baghouse
EU6-44	44	Gluten Recycle	Baghouse
EU4-46	46	Starch Bin #13	Baghouse

<b>Emission Unit ID</b>	<b>SV #</b>	<b>Equipment Description</b>	<b>Add-on control device</b>
EU4-47	47	Starch Bin #14	Baghouse
EU4-48	48	Starch Dryer Loadout	Baghouse

- (2) The equipment identified in Condition XIII.(E)(1) shall be properly installed, operated and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the germ, gluten, and starch cooling and storage equipment shall be kept on site and readily available to Department representatives.
- (3) The operation of each dry dust collector (baghouse) shall be in accordance with the following requirements: {Title 129, Chapter 19}
  - (a) The dry dust collectors shall be operated whenever the associated emission units are in operation.
  - (b) The dry dust collectors shall be properly installed, operated and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the dry dust collectors shall be kept on site and readily available to Department representatives.
  - (c) Each dry dust collector shall be equipped with an operational pressure differential indicator. The pressure differential indicator readings shall be recorded at least once each day that the associated dry dust collector is operating. The pressure indicator shall be properly installed, operated, calibrated, and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the pressure differential indicator shall be kept on site and readily available to Department representatives.
  - (d) Dry dust collector filter bags/cartridges are to be inspected and/or replaced according to the operation and maintenance manual or more frequently as indicated by pressure differential indicator readings or other indication of unit failure.
  - (e) Routine observations (at least once each day during daylight hours of dry dust collector operation) shall be conducted to determine whether there are visible emissions from the stack, leaks, noise, atypical pressure differential readings, or other indications, which may necessitate corrective action. Corrective action shall be taken immediately if necessary.
  - (f) Collected waste material from the dry dust collectors shall be handled, transported, and stored in a manner that ensures compliance with Condition X.
  - (g) The source shall maintain on-site an inventory of spare bags/cartridges of each type used to ensure rapid replacement in the event of bag/cartridge failure.

- (4) Emissions from the germ, gluten, and starch cooling and storage operations shall not exceed the emission limits in Table 8 (3- hour or test method average). {Title 129, Chapters 4 and 19}

**Table 8. Germ, Gluten, and Starch Cooling and Storage Emission Limits**

SV #	Equipment Description	PM/PM <sub>10</sub> (lbs/hr)	VOC (lb/hr)
9	Germ Cooler # 1-3	2.04	5.1
12	Germ Cooler # 4	1.55	6.5
17	Gluten Cooler # 1	1.25	2.08
19	Gluten Cooler #2	1.58	2.62
20	Starch Storage Bin # 11	0.03	
21	Starch Storage Bin # 12	0.03	
22	Starch Storage Bin # 9 (Off-Spec Starch)	0.03	
23	Starch Storage Bin # 10	0.03	
24	Gluten Storage Bin # 7	0.03	
25	Gluten Storage Bin # 8	0.03	
26	Gluten Storage Bin # 5	0.03	
27	Gluten Storage Bin # 6	0.03	
28	Gluten Storage Bin # 3	0.03	
29	Gluten Storage Bin # 4	0.03	
30	Gluten Storage Bin # 1	0.03	
31	Gluten Storage Bin # 2	0.03	
44	Gluten Recycle	0.11	0.2
46	Starch Bin #13	0.06	
47	Starch Bin #14	0.06	
48	Starch Dryer Loadout	0.11	

- (5) In order to demonstrate compliance with Condition XIII.(E)(4) and to verify assumptions used in the permit application, the source shall conduct performance tests as specified in the Table 9. The performance test shall be conducted in accordance with Condition XIII.(V) and shall include speciation and quantification of the HAP composition of the emissions. VOC emissions shall be expressed as total mass of VOC. {Title 129, Chapter 34}

**Table 9. Germ, Gluten, and Starch Cooling and Storage Test Requirements**

SV #	Equipment Description	PM/PM <sub>10</sub> Test Required	VOC/HAP Test Required
9	Germ Cooler # 1-3	Yes	Yes
12	Germ Cooler # 4	Yes <sup>1</sup>	Yes <sup>1</sup>
17	Gluten Cooler # 1	Yes	Yes
19	Gluten Cooler #2	Yes <sup>2</sup>	Yes <sup>2</sup>
20	Starch Storage Bin # 11	No	No

<b>SV #</b>	<b>Equipment Description</b>	<b>PM/PM<sub>10</sub> Test Required</b>	<b>VOC/HAP Test Required</b>
21	Starch Storage Bin # 12	No	No
22	Starch Storage Bin # 9 (Off-Spec Starch)	No	No
23	Starch Storage Bin # 10	No	No
24	Gluten Storage Bin # 7	No	No
25	Gluten Storage Bin # 8	No	No
26	Gluten Storage Bin # 5	No	No
27	Gluten Storage Bin # 6	No	No
28	Germ Storage Bin # 3	No	No
29	Germ Storage Bin # 4	No	No
30	Germ Storage Bin # 1	No	No
31	Germ Storage Bin # 2	No	No
44	Gluten Recycle	Yes <sup>2</sup>	Yes <sup>2</sup>
46	Starch Bin #13	No	No
47	Starch Bin #14	No	No
48	Starch Dryer Loadout	No	No

<sup>1</sup>Initial performance testing is required for SV#9 and 12; however, only SV#9 must be tested if the performance test demonstrates compliance. If the test indicates non-compliance, the other emission point shall be tested to independently verify compliance.

<sup>2</sup>Initial performance testing is required for SV#17, 19 and 44; however, only SV#17 must be tested if the performance test demonstrates compliance. If the test indicates non-compliance, the other emission points shall be tested to independently verify compliance.

(F) The following conditions apply to: FERMENTATION AND DISTILLATION OPERATIONS

- (1) VOC and HAP emissions from the fermentation and distillation operations shall be controlled by three scrubbers (EU7-32, EU7-33, and EU7-34). {Title 129, Chapters 19 and 27}
- (2) The operation of the scrubbers shall be in accordance with the following requirements: {Title 129, Chapters 19 and 27}
  - (a) The scrubbers shall be operated at all times when the associated emission units are in operation.
  - (b) The scrubbers shall be properly designed, installed, operated and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the scrubbers shall be kept on site and readily available to Department representatives.
  - (c) The scrubbers shall be equipped with indicators of scrubbing liquid flow rate and pressure differential. Operating parameter readings shall be recorded at least once each day the scrubbers are in operation. The indicators shall be properly installed, operated, calibrated, and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of

the operating parameter indicators shall be kept on site and readily available to Department representatives.

- (d) Routine observations (at least once each day of scrubber operation) shall be conducted to determine whether there are leaks, noise, atypical operating parameters (e.g., scrubbing liquid flow rate), or other indications that may necessitate corrective action.
- (3) The total emissions from the scrubber stacks (SV #32, 33, and 34) shall not exceed the following emission limits (3-hour or test method average). {Title 129, Chapters 19}
  - (a) 2.5 lbs/hr SO<sub>2</sub>
  - (b) 13.5 lbs/hr VOC
- (4) The scrubbers shall each have a minimum control efficiency of 65 percent for combined HAPs or shall have a HAP exhaust concentration of 20 ppmvd or less, and shall each have a minimum control efficiency of 95 percent for VOCs or shall have a VOC exhaust concentration of 20 ppmvd or less. {Title 129, Chapter 27; Consent Decree No. 03-CV-2066}
  - (a) A weighted average of the control efficiency for the combined HAPs shall be calculated using the following formula:

$$\text{Efficiency} = \left( 1 - \left( \frac{\sum C}{\sum U} \right) \right) * 100$$

Where: Efficiency = the combined HAP control efficiency  
C = the controlled (outlet) individual HAP emission rates (lbs/hr)  
U = the uncontrolled (inlet) individual HAP emission rates (lbs/hr)

- (b) Following HAP efficiency testing, ADM shall submit a revised BACT analysis with the results if 65% reduction or 20 ppmvd is not achieved.
- (c) If the scrubbers are unable to achieve a control efficiency of 65 percent or 20 ppmvd for combined HAPs, the limit may be subject to revisions after the opportunity for public comment.
- (5) In order to demonstrate compliance with Condition XIII.(F)(3) and to verify the assumptions used in the permit application, the source shall conduct a performance test for SO<sub>2</sub>, VOC, and HAP on the CO<sub>2</sub> scrubber stacks (SV #32, 33, and 34). In addition, the performance test shall determine the VOC and HAP control efficiency of the scrubbers to demonstrate compliance with Condition XIII.(F)(4). The performance test shall be conducted in accordance with Condition XIII.(V) and shall include speciation and quantification of the HAP



composition of the emissions. VOC emissions shall be expressed as total mass of VOC. {Title 129, Chapter 34}

(G) The following conditions apply to: STORAGE TANKS

- (1) The storage tanks consist of the internal floating-roof vertical aboveground tanks presented in Table 10: {Title 129, Chapters 18, 19, and 27}

**Table 10. Storage Tanks**

<b>Emission Unit ID</b>	<b>Equipment Description</b>	<b>Capacity (gallons)</b>
EU7-TK01	Day Tank A, ethanol	100,000
EU7-TK02	Day Tank B, ethanol	100,000
EU7-TK03	Rerun Tank, ethanol	34,000
EU7-TK04	Day Tank C, ethanol	100,000
EU7-TK05	Denaturant Tank	42,420
EU7-TK06	Denatured Ethanol Tank	2,000,000
EU7-TK07	Corrosion Inhibitor Tank	3,800
EU7-TK08	Denaturant Tank	100,000

- (2) The requirements of the NSPS for Volatile Organic Liquid Storage Vessels in 40 CFR 60, Subparts A and Kb {Title 129, Chapter 18, Sections 001.01 and 001.62} apply to storage tanks EU-TK05, EU-TK06, and EU-TK08. The requirements include, but are not limited to, the following: {Title 129, Chapters 18 and 27}
- (a) The tanks shall each be equipped with an internal floating roof, in accordance with the specifications in 40 CFR 60.112b(a)(1).
- (b) The tanks shall each be visibly inspected and repaired in accordance with testing and procedures per 40 CFR 60.113b(a).
- (c) The owner or operator of the affected tanks shall report and keep records as described in 40 CFR 60.115b – Reporting and recordkeeping requirements and in 40 CFR 60.116b – Monitoring of operations.
- (3) The requirements of Conditions XIII.(G)(2)(a-b) apply to storage tank EU-TK01, EU-TK02, EU-TK03, and EU-TK04. {Title 129, Chapter 27}

(H) The following condition applies to: LIQUID PRODUCT LOADOUT

- (1) The source shall use submerged and/or bottom fill loading when transferring liquid product from the storage tanks to tanker railcar or tanker truck. {Title 129, Chapters 19 and 27}
- (2) Truck and railcar loadout of liquid product shall be controlled by a closed vapor recovery system with a flare (EU7-90) at all times liquid product loadout is occurring. {Title 129, Chapters 19 and 27}

- (a) The vapor recovery system and flare shall be properly designed, installed, operated and maintained in order to capture the vapor generated during product loadout. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the vapor recovery system and flare shall be kept on site and readily available to Department representatives.
  - (b) When liquid loadout is occurring, a flame shall be present at the flare. The facility must install an appropriate safety device or flame monitoring system to ensure that loadout cannot occur without the presence of a flame. The safety device or flame monitoring system shall be properly installed, operated, calibrated and maintained. Manufacturer's documentation shall be kept on site and readily available to Department representatives.
- (I) The following conditions apply to REFINERY CARBON FURNACES #1 and #2:
  - (1) Carbon furnaces #1 (EU8-35) and #2 (EU8-36) shall burn natural gas only, and shall be equipped with afterburners. The furnaces shall be properly installed, operated and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the furnaces shall be kept on site and readily available to Department representatives.
  - (2) The emissions from each carbon furnace shall first be combusted by an afterburner and further controlled by a venturi wet scrubber with impingement trays. {Title 129, Chapters 19 and 27}
  - (3) The operation of each scrubber shall be in accordance with the following requirements: {Title 129, Chapters 19 and 27}
    - (a) The scrubbers shall be operated at all times when the associated emission units are in operation.
    - (b) The scrubbers shall be properly designed, installed, operated and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the scrubbers shall be kept on site and readily available to Department representatives.
    - (c) The scrubbers shall be equipped with indicators of scrubbing liquid flow rate, pH, and scrubber pressure differential. Operating parameter readings shall be recorded at least once each day the scrubbers are in operation. The indicators shall be properly installed, operated, calibrated, and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the operating parameter indicators shall be kept on site and readily available to Department representatives.

- (d) Routine observations (at least once each day of scrubber operation) shall be conducted to determine whether there are leaks, noise, atypical operating parameters (e.g., scrubbing liquid flow rate), or other indications that may necessitate corrective action.
- (4) The total emissions from the wet scrubber for carbon furnace #1 stack (SV-35) shall not exceed the following emission limits (3-hour or test method averaged). {Title 129, Chapters 4, 19, and 27}
  - (a) 1.88 pounds per hour PM
  - (b) 1.00 pounds per hour PM<sub>10</sub>
  - (c) 3.38 pounds per hour NO<sub>x</sub>
  - (d) 2.0 pounds per hour SO<sub>2</sub>
  - (e) 7.63 pounds per hour CO
  - (f) 2.7 pounds per hour VOC
- (5) The total emissions from the wet scrubber for carbon furnace #2 stack (SV-36) shall not exceed the following emission limits (3-hour or test method average) {Title 129, Chapters 4, 19, and 27}:
  - (a) 3.14 pounds per hour PM
  - (b) 1.50 pounds per hour PM<sub>10</sub>
  - (c) 5.64 pounds per hour NO<sub>x</sub>
  - (d) 3.3 pounds per hour SO<sub>2</sub>
  - (e) 8.14 pounds per hour CO
  - (f) 3.8 pounds per hour VOC
- (J) The following condition applies to: BOILERS # 1, 2, 3, 4, and 5
  - (1) Only natural gas shall be burned as fuel in Boiler #1 (EU9-38), Boiler #2 (EU9-39), Boiler #3 (EU9-40), Boiler #4 (EU9-41), and Boiler #5 (EU9-98). {Title 129, Chapters 4 and 19}
  - (2) On or before April 30, 2006, the existing burner in Boiler #1 (EU9-38) shall be replaced with a low-NO<sub>x</sub> burner. Upon completion of this replacement, NO<sub>x</sub> emissions from Boiler #1 shall meet the limits presented in Condition XIII.(J)(3). (Consent Decree (United States v. ADM, No. 03-CV-2066 (C.D. Illinois)))
  - (3) The total emissions from the boiler stacks shall not exceed the emission limits in Table 11 (3-hour or test method average). {Title 129, Chapters 4 and 19}

**Table 11. Boilers #1, 2, 3, 4, and 5 Emission Limits**

<b>Emission Unit ID</b>	<b>SV#</b>	<b>Boiler #</b>	<b>NO<sub>x</sub> (lb/MMBtu)</b>	<b>CO (lb/hr)</b>
EU9-38	38	1	0.2 0.06 <sup>a</sup>	
EU9-39	39	2	0.074	
EU9-40	40	3	0.074 <sup>b</sup>	
EU9-41	40	4	0.074 <sup>b</sup>	
EU9-42	98	5	0.036	23.6

<sup>a</sup> Boiler #1 subject to 0.06 (lb/MMBtu) NO<sub>x</sub> limit upon completion of installation of the low-NO<sub>x</sub> burner required by Condition XIII.(J)(2).

<sup>b</sup> These boilers share a common stack and a single CEMS. The emission limits are total for both boilers.

- (4) The NSPS for Industrial-Commercial-Institutional Steam Generating Units, Subpart Db {Title 129, Chapter 18, Section 001.22} apply to Boilers # 1 thru #5 (EU9-38, 9-39, 9-40, 9-41, and 9-98}. The requirements include, but are not limited to, the following:
- (a) NO<sub>x</sub> emissions shall not exceed 0.1 lbs/MMBtu (30-day rolling average). This emission limit applies at all times including periods of startup, shutdown or malfunction.
  - (b) Performance and compliance testing shall be conducted in accordance with Title 129, Chapter 18, NSPS, Section 001.01 General Provisions, and as required by 40 CFR 60.46b(e) and Condition XIII.(V).
  - (c) The source shall install, calibrate, maintain, and operate a CEMS or approved alternative in accordance with the Subpart for each boiler measuring the NO<sub>x</sub> emissions. Boilers #3 (EU9-40) and #4 (EU9-41) share a common stack and shall use a single CEMS.
  - (d) The Requirements for Performance Specifications 2 - Specifications and Test Procedures for SO<sub>2</sub> and NO<sub>x</sub> Continuous Emission Monitoring Systems in Stationary Sources found in 40 CFR 60 Appendix B shall be followed for the CEMS required under the Condition XIII.(J)(4)(c).
  - (e) Quality assurance for the CEMS required under the Condition XIII.(J)(4)(c) shall be conducted according to the requirements of 40 CFR 60 Appendix F. The report of the Relative Accuracy Test Audit required by the 40 CFR 60 Appendix F or a similar procedure shall be submitted to the Department within 45 days of completion of the test.
  - (f) The source shall record and maintain records of the amount of natural gas combusted during each day in each boiler unless EPA Region VII approves an alternative record-keeping frequency. {40 CFR 60.49b(d)}

- (g) The source shall submit notification of the date of construction, anticipated startup, and actual startup, as provided by Title 40 CFR 60.7. {40 CFR 60.49b(a)}
- (5) The requirements of the NESHAP for Commercial, Industrial, and Institutional Boilers and Process Heaters in 40 CFR 63, Subpart DDDDD {Title 129, Chapter 28, Section 001.90} apply to the existing natural gas fired Boilers #1 through #4 (EU9-38, EU9-39, EU9-40, and EU9-41). These boilers comprise the affected source for the existing large gaseous fuel subcategory. Pursuant to 40 CFR 63.7506(b)(1) and 40 CFR 63.7545(c), the source submitted an Initial Notification containing the information specified in 40 CFR 63.9(b)(2) on March 10, 2005. {Title 129, Chapters 27 and 28}
  - (6) The requirements of the NESHAP for Commercial, Industrial, and Institutional Boilers and Process Heaters in 40 CFR 63, Subpart DDDDD {Title 129, Chapter 28, Section 001.90} apply to the new natural gas fired Boiler #5 (EU9-98). This boiler is considered a new gaseous fuel unit and shall comply with the requirements in this subpart upon startup of this boiler. The requirements include, but are not limited to, the following:
    - (a) The emission limits and work practice standards pursuant to 40 CFR 63.7500.
    - (b) The testing, compliance, and monitoring requirements pursuant to 40 CFR 63.7505-63.7541.
    - (c) The notification, reporting, and recordkeeping requirements pursuant to 40 CFR 63.7545-63.7560.
- (K) The following conditions apply to: CFB BOILERS EU9-1A and EU9-1B
    - (1) Only coal and alternative fuel blends (coal mixed with up to 20% by weight biomass, petroleum coke, or tire-derived fuel) shall be burned in the CFB boilers (EU9-1A and EU9-1B). {Title 129, Chapters 4 and 19}
    - (2) Emissions from the CFB boilers shall be controlled by limestone injection, ammonia injection (SNCR), and two fabric filter baghouses (one for each boiler), exhausting through individual flues of a single stack (SV-COGEN1). {Title 129, Chapters 4, 19, and 27}
    - (3) The operation of the dry dust collectors (baghouses) shall be in accordance with the following requirements: {Title 129, Chapters 4 and 19}
      - (a) The dry dust collectors shall be operated whenever the associated emission units are in operation.
      - (b) The dry dust collectors shall be properly installed, operated and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of

the dry dust collectors shall be kept on site and readily available to Department representatives.

- (c) The dry dust collectors shall be equipped with an operational pressure differential indicator. The pressure differential indicator readings shall be recorded at least once each day that the associated dry dust collector is operating. The pressure indicator shall be properly installed, operated, calibrated, and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the pressure differential indicator shall be kept on site and readily available to Department representatives.
  - (d) Dry dust collector filter bags/cartridges are to be inspected and/or replaced according to the operation and maintenance manual, or more frequently as indicated by pressure differential indicator readings or other indication of unit failure.
  - (e) Routine observations (at least once each day during daylight hours of dry dust collector operation) shall be conducted to determine whether there are leaks, noise, atypical pressure differential readings, or other indications, which may necessitate corrective action. Corrective action shall be taken immediately if necessary.
  - (f) Collected waste material from the dry dust collectors shall be handled, transported, and stored in a manner that ensures compliance with Condition X.
  - (g) The source shall maintain on-site an inventory of spare bags/cartridges of each type used to ensure rapid replacement in the event of bag/cartridge failure.
- (4) The total emissions from the CFB boilers stack (SV-COGEN1) shall not exceed the emission limits in Table 12. {Title 129, Chapter 4, 19, and 27}

**Table 12. CFB Boiler Emission Limits**

<b>Pollutant / Parameter</b>	<b>Limit</b>	<b>Averaging Period</b>
PM (filterable only)	0.015 lb/MMBtu	Average of 3 runs
PM <sub>10</sub> (filterable and condensable)	0.025 lb/MMBtu	Average of 3 runs
VOC	0.007 lb/MMBtu	Average of 3 runs
F (as HF)	0.0012 lb/MMBtu	Average of 3 runs
H <sub>2</sub> SO <sub>4</sub>	0.01 lb/MMBtu	Average of 3 runs
NO <sub>x</sub>	0.07 lb/MMBtu	30-day rolling average excluding period of “cold startup” <sup>1</sup>
Pb	0.0002 lb/MMBtu	Average of 3 runs
SO <sub>2</sub>	0.11-0.20 lb/MMBtu	30-day rolling average <sup>2,3</sup>
SO <sub>2</sub>	3,750 lbs/hr	3-hour average (NAAQS)
CO	0.1 lb/MMBtu	30-day rolling average <sup>2</sup>
CO	150 lbs/hr	3 hour average

<sup>1</sup> A cold startup period is defined as that period of time when a coal-fired cogen boiler is proceeding to increase the temperature in the lower combustor from less than 400°F to at least 1500°F. This period shall last no more than 48 hours and NO<sub>x</sub> emissions data from this period shall be excluded when determining compliance with the limits established. Ammonia injection shall begin as soon as the lower combustor temperature reaches 1500°F and the cold startup period will end at this time. All data from cold startup periods after the first 48 hours, or while ammonia is injected in the boiler, will be included in determining compliance with the optimized limit.

<sup>2</sup> Excludes periods of start-up and shutdown.

<sup>3</sup> 30-day rolling average SO<sub>2</sub> limit will vary depending on fuel sulfur content.

- (5) The Permittee shall not discharge or cause the discharge of SO<sub>2</sub> from the CFB boilers to the atmosphere in excess of the following:

A calculated emission limit, on a 30-day rolling average, as set forth below, for any BOD:

$$\frac{0.20A + 0.11B + 0.10C_1 + \dots + 0.10C_n}{30} \quad \text{lb/MMBtu heat input}$$

Where:

A = Number of BODs, during 30 BODs prior to the calculation, when the uncontrolled SO<sub>2</sub> emission potential of the combusted fuel was 2.0 lb/MMBtu or greater based on daily as-fired fuel sulfur analysis.

B = Number of BODs, during 30 BODs prior to the calculation, when the uncontrolled SO<sub>2</sub> emission potential of the combusted fuel was 1.1 lb/MMBtu or less based on daily as-fired fuel sulfur analysis.

C<sub>(1)</sub> = Uncontrolled SO<sub>2</sub> emission potential of the combusted fuel for each BOD, during 30 BODs prior to the calculation, when the uncontrolled SO<sub>2</sub> emission potential of the combusted fuel was greater than 1.1 lb/MMBtu and less than 2.0 lb/MMBtu.

C<sub>(n)</sub> = Each additional BOD when the uncontrolled SO<sub>2</sub> emission potential of the combusted coal was greater than 1.1 lb/MMBtu and less than 2.0 lb/MMBtu.

BOD = Boiler Operating Day is a day when the boiler operates at least 1 hour, not including periods of startup and shutdown.

For purposes of determining the applicable SO<sub>2</sub> emission limit, the uncontrolled SO<sub>2</sub> emission potential of the coal, on a 30-day rolling average, shall be based on daily as-fired fuel samples obtained during a period of 30 BODs. Any BOD that does not have valid sulfur analysis results shall be considered a BOD where the uncontrolled SO<sub>2</sub> emission potential was less than 1.1 lb/MMBtu (B).

- (6) In order to demonstrate compliance with Condition XIII.(K)(4) and to verify the assumptions used in the permit application, the source shall conduct a performance test for each boiler for the pollutants listed in Condition XIII.(K)(4), except as described in Condition XIII.(K)(7)(c) for NO<sub>x</sub>, SO<sub>2</sub>, and CO. The performance test shall be performed in accordance with Condition XIII.(V). The performance test for PM, PM<sub>10</sub>, and VOC shall be completed within 180 days after first combusting each fuel blend. VOC emissions shall be expressed as total mass of VOC. The performance test for F (as HF), H<sub>2</sub>SO<sub>4</sub>, and Pb shall be completed with the worst-case fuel for these pollutants as determined by fuel analysis. Compliance with the NO<sub>x</sub>, SO<sub>2</sub>, and CO limits in Condition XIII.(K)(4) shall be demonstrated using CEMS data as required by Condition XIII.(K)(7)(c). {Title 129, Chapter 34}
- (7) The NSPS for Industrial-Commercial-Institutional Steam Generating Units, Subpart Db {Title 129, Chapter 18, Section 001.22} apply to boilers EU9-1A and EU9-1B, exhausting through stack (SV-COGEN1). The requirements include, but are not limited to, the following: {40 CFR 60.40b}
  - (a) Emissions from the CFB boilers shall not exceed the emission limits in Table 13. Compliance with the PM, NO<sub>x</sub>, and SO<sub>2</sub> limits shall be demonstrated by compliance with Condition XIII.(K)(4).

**Table 13. CFB Boiler NSPS Limits**

Pollutant /Parameter	Limit	Averaging Period
NO <sub>x</sub>	0.20 lb/MMBtu	30-day rolling <sup>1</sup>
SO <sub>2</sub>	1.2 lb/MMBtu and 92% reduction or 0.20 lb/MMBtu	30-day rolling <sup>1</sup>
Opacity	20 % ( 27 % for one 6-minute period per hour)	6-minute
PM (filterable only)	0.03 lb/MMBtu	Average of 3 runs

<sup>1</sup> Includes periods of start-up, shutdown, and malfunction.



- (b) Performance and compliance testing shall be conducted in accordance with Title 129, Chapter 18, NSPS, Section 001.01 General Provisions, and as required by 40 CFR 60.45b(c), 60.46b(d), 60.46b(e), and Condition XIII.(V).
  - (c) The source shall install, calibrate, maintain, and operate a CEMS or approved alternative for each boiler in accordance with the Subpart for measuring SO<sub>2</sub>, CO, and NO<sub>x</sub> emissions, and a COMS for measuring opacity.
  - (d) The Requirements for Performance Specification 2 - Specifications and Test Procedures for SO<sub>2</sub> and NO<sub>x</sub> Continuous Emission Monitoring Systems in Stationary Sources, and Performance Specification 4 – Specifications and Test Procedures for CO Continuous Emission Monitoring Systems in Stationary Sources found in 40 CFR 60 Appendix B, shall be followed for each CEMS required under Condition XIII.(K)(7)(c).
  - (e) Quality Assurance for the continuous emissions monitoring systems required under the Condition XIII.(K)(7)(c) shall be conducted according to the requirements of 40 CFR 60 Appendix F. The report of the Relative Accuracy Test Audit required by the 40 CFR 60 Appendix F or a similar procedure shall be submitted to the Department within 45 days of completion of the test.
  - (f) The source shall record and maintain records of the amount of coal, biomass, petroleum coke, and TDF combusted during each day in each boiler unless EPA Region VII approves an alternative record-keeping frequency. {40 CFR 60.49b(d)}
  - (g) The source shall submit notification of the date of construction, anticipated startup, and actual startup, as provided by Title 40 CFR 60.7. {40 CFR 60.49b(a)}
- (8) The requirements of the NESHAP for Commercial, Industrial, and Institutional Boilers and Process Heaters in 40 CFR 63, Subpart DDDDD {Title 129, Chapter 28, Section 001.90} apply to boilers EU9-1A and EU9-1B, exhausting through stack (SV-COGEN1). These boilers comprise the affected source for the new large solid fuel subcategory and shall comply with the requirements in this subpart upon startup of these units. The requirements include, but are not limited to, the following:
- (a) The emission limits and work practice standards pursuant to 40 CFR 63.7500.
  - (b) The testing, compliance, and monitoring requirements pursuant to 40 CFR 63.7505-63.7541.
  - (c) The notification, reporting, and recordkeeping requirements pursuant to 40 CFR 63.7545-63.7560.

(L) The following conditions apply to: COAL, FLY ASH, BED ASH, AND LIMESTONE HANDLING, STORAGE, AND TRANSPORT OPERATIONS:

- (1) PM and PM<sub>10</sub> emissions from all coal, fly ash, bed ash and limestone handling, storage, and transport equipment shall be controlled by the control equipment presented in Table 14: {Title 129, Chapters 4 and 19}

**Table 14. Coal, Ash, and Limestone Handling Equipment**

<b>Emission Unit ID</b>	<b>SV #</b>	<b>Equipment Description</b>	<b>Add-on control device</b>
EU9-2	COGEN2	Rotary Car Dumper/Truck Dump Building Unit 1	Baghouse
EU9-3	COGEN3	Rotary Car Dumper/Truck Dump Building Unit 2	Baghouse
EU9-4	COGEN4	Coal Storage Dome/Reclaim Tunnel	Baghouse
EU9-5	COGEN5	Crusher Tower	Baghouse
EU9-6	COGEN6	Powerhouse Bunker Bay	Baghouse
EU9-7	COGEN7	Fly Ash Transfer/Storage Unit 1	Baghouse
EU9-8	COGEN8	Fly Ash Transfer/Storage Unit 2	Baghouse
EU9-9	COGEN9	Bottom Ash Collection Unit 1	Baghouse
EU9-10	COGEN10	Bottom Ash Collection Unit 2	Baghouse
EU9-11	COGEN11	Bottom Ash Transfer/Storage Unit 1	Baghouse
EU9-12	COGEN12	Bottom Ash Transfer/Storage Unit 2	Baghouse
EU9-13	COGEN13	Limestone Storage Unit 1	Baghouse
EU9-14	COGEN14	Limestone Storage Unit 2	Baghouse
EU9-15	COGEN15	Limestone Transfer Unit 1	Baghouse
EU9-16	COGEN16	Limestone Transfer Unit 2	Baghouse

- (2) The operation of each dry dust collector (baghouse) identified in Condition XIII.(L)(1) shall be in accordance with the following requirements: {Title 129, Chapters 4 and 19}
- (a) The dry dust collectors shall be operated whenever the associated emission units are in operation.
  - (b) The dry dust collectors shall be properly installed, operated and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the dry dust collectors shall be kept on site and readily available to Department representatives.
  - (c) Each dry dust collectors shall be equipped with an operational pressure differential indicator. The pressure differential indicator readings shall be recorded at least once each day that the associated dry dust collector is operating. The pressure indicator shall be properly installed, operated, calibrated, and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation,

inspection and maintenance of the pressure differential indicator shall be kept on site and readily available to Department representatives.

- (d) Dry dust collector filter bags/cartridges are to be inspected and/or replaced according to the operation and maintenance manual, or more frequently as indicated by pressure differential indicator readings or other indication of unit failure.
  - (e) Routine observations (at least once each day during daylight hours of dry dust collector operation) shall be conducted to determine whether there are visible emissions from the stack, leaks, noise, atypical pressure differential readings, or other indications, which may necessitate corrective action. Corrective action shall be taken immediately if necessary.
  - (f) Collected waste material from the dry dust collectors shall be handled, transported, and stored in a manner that ensures compliance with Condition X.
  - (g) The source shall maintain on-site an inventory of spare bags/cartridges of each type used to ensure rapid replacement in the event of bag/cartridge failure.
- (3) The emissions from the coal, fly ash, bed ash and limestone handling, storage, and transport operations shall not exceed the following emission limits in Table 15 (3- hour or test method average). {Title 129, Chapters 4 and 19}

**Table 15. Coal, Ash, and Limestone Handling Emission Limits**

<b>SV #</b>	<b>Equipment Description</b>	<b>PM/PM<sub>10</sub> emissions (lb/hr)</b>
COGEN2	Rotary Car Dumper/Truck Dump Building Unit 1	0.71
COGEN3	Rotary Car Dumper/Truck Dump Building Unit 2	0.71
COGEN4	Coal Storage Dome/Reclaim Tunnel	0.68
COGEN5	Crusher Tower	0.51
COGEN6	Powerhouse Bunker Bay	0.55
COGEN7	Fly Ash Transfer/Storage Unit 1	0.24
COGEN8	Fly Ash Transfer/Storage Unit 2	0.24
COGEN9	Bottom Ash Collection Unit 1	0.08
COGEN10	Bottom Ash Collection Unit 2	0.08
COGEN11	Bottom Ash Transfer/Storage Unit 1	0.08
COGEN12	Bottom Ash Transfer/Storage Unit 2	0.08
COGEN13	Limestone Storage Unit 1	0.21
COGEN14	Limestone Storage Unit 2	0.21
COGEN15	Limestone Transfer Unit 1	0.21
COGEN16	Limestone Transfer Unit 2	0.21

- (4) In order to demonstrate compliance with Condition XIII.(L)(3), the source shall conduct a performance test for PM and PM<sub>10</sub> on each of the Stacks/vents (SV) listed in Condition XIII.(L)(3) as specified in Table 16. The performance test shall be conducted in accordance with Condition XIII.(V). {Title 129, Chapter 34}

**Table 16. Coal, Ash, and Limestone Handling Test Requirements**

SV #	Equipment Description	PM/PM <sub>10</sub> Testing Required
COGEN2	Rotary Car Dumper/Truck Dump Building Unit 1	Yes <sup>1</sup>
COGEN3	Rotary Car Dumper/Truck Dump Building Unit 2	Yes <sup>1</sup>
COGEN4	Coal Storage Dome/Reclaim Tunnel	Yes <sup>1</sup>
COGEN5	Crusher Tower	Yes <sup>1</sup>
COGEN6	Powerhouse Bunker Bay	Yes <sup>1</sup>
COGEN7	Fly Ash Transfer/Storage Unit 1	Yes <sup>2</sup>
COGEN8	Fly Ash Transfer/Storage Unit 2	Yes <sup>2</sup>
COGEN9	Bottom Ash Collection Unit 1	Yes <sup>2</sup>
COGEN10	Bottom Ash Collection Unit 2	Yes <sup>2</sup>
COGEN11	Bottom Ash Transfer/Storage Unit 1	Yes <sup>2</sup>
COGEN12	Bottom Ash Transfer/Storage Unit 2	Yes <sup>2</sup>
COGEN13	Limestone Storage Unit 1	Yes <sup>3</sup>
COGEN14	Limestone Storage Unit 2	Yes <sup>3</sup>
COGEN15	Limestone Transfer Unit 1	Yes <sup>3</sup>
COGEN16	Limestone Transfer Unit 2	Yes <sup>3</sup>

<sup>1</sup> Initial performance testing is required for SV#COGEN2, COGEN3, COGEN4, COGEN5, and COGEN6; however, only COGEN2 must be tested if the performance test demonstrates compliance. If the test indicates non-compliance, the other emission points shall be tested to independently verify compliance.

<sup>2</sup> Initial performance testing is required for SV#COGEN7, COGEN8, COGEN9, COGEN10, COGEN11 and COGEN12; however, only COGEN7 must be tested if the performance test demonstrates compliance. If the test indicates non-compliance, the other emission points shall be tested to independently verify compliance.

<sup>3</sup> Initial performance testing is required for SV#COGEN13, COGEN14, COGEN15, and COGEN16; however, only COGEN13 must be tested if the performance test demonstrates compliance. If the test indicates non-compliance, the other emission points shall be tested to independently verify compliance.

- (5) The requirements of the NSPS for Coal Preparation Plants in 40 CFR 60, Subparts A and Y {Title 129, Chapter 18, Sections 001.01 and 001.08} apply to all thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems, and coal transfer and loading systems operations at this facility (EU9-4, EU9-5, and EU9-6). These requirements include, but are not limited to, the following:

- (a) Opacity of visible emissions from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system shall not exhibit 20 percent opacity or greater. {40 CFR 60.252(c)}
- (b) The opacity of the coal processing and conveying equipment, coal storage system, and coal transfer and loading system shall be measured within 90 days of start-up to demonstrate compliance with the opacity limit given in Condition XIII.(L)(5)(a). Compliance Method 9 specified in 40 CFR 60.11 shall be used to measure opacity {40 CFR 60.254(b)(2)}.

(M) The following conditions apply to: COOLING TOWERS

- (1) The four cooling towers (EU13-E1-6, EU13-F1-3, EU9-17-18, and EU9-19-22) shall be properly installed, operated and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the cooling towers shall be kept on site and readily available to Department representatives. {Title 129, Chapters 4 and 19}
- (2) The drift loss for EU13-E1-6 and EU13-F1-3 shall not exceed 0.008 percent. The drift loss for EU9-17-18 and EU9-19-22 shall not exceed 0.0005 percent. Verification of drift loss will be by manufacturer's guarantee. Manufacturer's drift loss guarantee shall be kept on site and readily available to Department representatives, upon request. {Title 129, Chapters 4 and 19}
- (3) The TDS concentration in the cooling water shall not exceed 2,500 ppm for any single sampling event. A TDS sample shall be collected from each cooling tower and tested at a minimum of once per calendar month. {Title 129, Chapters 4 and 19}

(N) The following conditions apply to: EQUIPMENT LEAKS

- (1) The requirements of the NSPS for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry in 40 CFR, Subparts A and VV {Title 129, Chapter 18, Sections 001.01 and 001.14} apply to all affected equipment. The requirements include, but are not limited to, the following:
  - (a) Equipment subject to 40 CFR 60 Subpart VV shall be each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by Subpart VV. {40 CFR 60.481}
  - (b) Compliance with NSPS, Subpart VV shall be demonstrated for all equipment within 180 days of initial startup. {40 CFR 60.482-1}
  - (c) Test methods and procedures shall be consistent with the requirements found in 40 CFR 60.485. The methods include:
    - (i) Method 21 shall be used to determine the presence of leaking sources. {40 CFR 60.485(b)(1)}

- (ii) Method 21 shall be used to determine the background level. {40 CFR 60.485(c)(2)}
- (iii) Procedures that conform to the general methods in ASTM E-260, E-168, E-169 (incorporated by reference – see § 60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment. {40 CFR 60.485(d)(1)}
- (iv) Standard reference texts or ASTM D-2879 (incorporated by reference – see § 60.17) shall be used to determine the vapor pressure of the components in the liquid in the light liquid service. {40 CFR 60.485(e)(1)}
- (d) The owner or operator shall report and keep records as described in 40 CFR 60.487 – Reporting requirements and in 40 CFR 60.486 – Recordkeeping requirements. Each owner or operator shall submit semiannual reports to the Department beginning six months after the initial startup date.
- (e) Emissions shall be controlled by the Leak Detection and Repair Program as defined in 40 CFR 60.482-1 through 60.482-10.

(O) The following conditions apply to: HAUL ROADS

- (1) All on-site haul roads with production-related truck traffic shall be paved. The paved haul roads shall comply with the following conditions: {Title 129, Chapters 19 and 32}
  - (a) The owner or operator shall develop, maintain, and implement a Truck Traffic Fugitive Control Strategy and Monitoring Plan to control emissions from haul roads to comply with Condition X. At a minimum, the requirements of the Plan shall include the following: {Title 129, Chapters 19 and 32}
    - (i) All paved haul roads shall be cleaned, using a vacuum sweeper, a minimum of three (3) times per week unless weather events are deemed not to warrant such cleaning.
    - (ii) For each day of operation, the owner or operator shall conduct a survey of the plant property and haul roads to determine if visible fugitive emissions are being generated and leaving plant property.
    - (iii) Documentation of all fugitive dust control measures implemented, any weather events deemed not to warrant road cleaning, and daily surveys shall be maintained in a log.

(P) The following conditions apply to: EMERGENCY EQUIPMENT

- (1) The emergency fire water-pump engines 1, 2, 3 and 4 (EU-95, EU-96, EU-107, and EU-108), the emergency generator SCU (EU-97), and the emergency generator warehouse 1 (EU-99) shall not exceed 400 operating hours per any period twelve (12) consecutive calendar months each. At no time during the first eleven (11) calendar months after the permit issuance date shall the sum of all the previous months' operating hours exceed 400 hours for each piece of listed emergency equipment. {Title 129, Chapters 4, 19, and 27}
- (2) Only diesel fuel (# 1 and # 2) shall be combusted in the emergency equipment. {Title 129, Chapters 4, 19, 20 and 24}
- (3) The emergency equipment shall be equipped with hour meters to record the operating hours to determine compliance with Condition XIII.(P)(1). The hour meters shall be properly installed, operated, calibrated, and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the hour meters shall be kept on site and readily available to Department representatives. {Title 129, Chapter 19}

(Q) The following conditions apply to: WASTEWATER TREATMENT

- (1) Biogas generated from the anaerobic digesters shall be collected and combusted in the anaerobic digester biogas flare (EU10-41) or in Gluten Flash Dryer #1 (EU6-16).
- (2) The biogas flare shall not exceed 2,190 operating hours per any period twelve (12) consecutive calendar months. At no time during the first eleven (11) calendar months after permit issuance shall the sum of all the previous months' operating hours exceed 2,190 hours. The pilot for the flare may operate continuously. {Title 129, Chapter 19}
- (3) The biogas flare shall be equipped with an hour meter or equivalent tracking system to record the operating hours to determine compliance with Condition XIII.(Q)(2). The hour meter shall be properly installed, operated, calibrated, and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the hour meter shall be kept on site and readily available to Department representatives. {Title 129, Chapter 19}
- (4) The biogas flare shall be properly designed, installed, operated and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the wastewater treatment tanks and flare shall be kept on site and readily available to Department representatives.

(R) The following conditions apply to: SODA ASH RECEIVING AND HCl STORAGE AND RECEIVING

- (1) HCl emissions from the HCl storage tanks shall be controlled by the acid gas scrubber (EU8-91). PM emissions from Soda Ash Receiving (EU8-63) shall be controlled by a wet scrubber. {Title 129, Chapters 19 and 27}

- (2) The operation of the scrubbers shall be in accordance with the following requirements: {Title 129, Chapter 27}
  - (a) The scrubbers shall be operated at all times when the material unloading is occurring.
  - (b) The scrubbers shall be properly designed, installed, operated and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the scrubber shall be kept on site and readily available to Department representatives.
  - (c) The scrubbers shall be equipped with indicators of scrubbing liquid flow rate and pressure differential. Operating parameter readings shall be recorded at least once each day the scrubbers are in operation. The indicators shall be properly installed, operated, calibrated, and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the operating parameter indicators shall be kept on site and readily available to Department representatives.
  - (d) Routine observations (at least once each day of scrubber operation) shall be conducted to determine whether there are leaks, noise, atypical operating parameters (e.g., scrubbing liquid flow rate), or other indications that may necessitate corrective action.
- (3) PM and PM<sub>10</sub> emissions from the Soda Ash Receiving scrubber vent (SV-63) shall not exceed 0.085 lbs/hr (3-hour or test method average). {Title 129, Chapter 19}
- (4) In order to demonstrate compliance with Condition XIII.(R)(3), the source shall conduct a performance test for PM and PM<sub>10</sub> on SV-63. The performance test shall be conducted in accordance with Condition XIII.(V). {Title 129, Chapter 34}
- (S) The following conditions apply to the LIME SILO BIN VENT:
  - (1) PM and PM<sub>10</sub> emissions from the lime silo bin (EU13-62) shall be captured and controlled by the lime silo bin baghouse. {Title 129, Chapters 4 and 19}
  - (2) The operation of the dry dust collector (baghouse) shall be in accordance with the following requirements: {Title 129, Chapters 4 and 19}
    - (a) The dry dust collector shall be operated whenever the associated emission units are in operation.
    - (b) The dry dust collector shall be properly installed, operated and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of



the dry dust collector shall be kept on site and readily available to Department representatives.

- (c) The dry dust collector shall be equipped with an operational pressure differential indicator. The pressure differential indicator readings shall be recorded at least once each day that the associated dry dust collector is operating. The pressure indicator shall be properly installed, operated, calibrated, and maintained. The manufacturer's operation and maintenance manual, or its equivalent, detailing proper operation, inspection and maintenance of the pressure differential indicator shall be kept on site and readily available to Department representatives.
  - (d) Dry dust collector filter bags/cartridges are to be inspected and/or replaced according to the operation and maintenance manual, or more frequently as indicated by pressure differential indicator readings or other indication of unit failure.
  - (e) Routine observations (at least once each day during daylight hours of dry dust collector operation) shall be conducted to determine whether there are visible emissions from the stack, leaks, noise, atypical pressure differential readings, or other indications, which may necessitate corrective action. Corrective action shall be taken immediately if necessary.
  - (f) Collected waste material from the dry dust collectors shall be handled, transported, and stored in a manner that ensures compliance with Condition X.
  - (g) The source shall maintain on-site an inventory of spare bags/cartridges of each type used to ensure rapid replacement in the event of bag/cartridge failure.
- (3) The PM and PM<sub>10</sub> emissions from the lime silo bin baghouse vent (SV-62) shall not exceed 0.13 pounds per hour (3-hour or test method average). {Title 129, Chapters 4, 19, and 20}.
- (4) In order to demonstrate compliance with Condition XIII.(S)(3), the source shall conduct a performance test for PM and PM<sub>10</sub> on the lime silo bin baghouse vent (SV-62). The performance test shall be conducted in accordance with Condition XIII.(V). {Title 129, Chapter 34}
- (T) The requirements of the NESHAP for Miscellaneous Organic Chemical Manufacturing in 40 CFR 63, Subpart FFFF {Title 129, Chapter 28, Section 001.78} apply to the miscellaneous organic chemical manufacturing process units at this source (including all storage tanks, transfer stations, pumps, compressors, agitators, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, and instrumentation systems used in the ethanol manufacturing process). The requirements include, but are not limited to, the following:

- (1) The emission limits, work practice standards, and compliance requirements pursuant to 40 CFR 63.2450-63.2490.
- (2) The notification, reporting, and recordkeeping requirements pursuant to 40 CFR 63.2515-63.2525.
- (U) The following conditions apply to the verification of the NAAQS modeling analysis {Title 129, Chapters 4 and 19}
  - (1) Stack heights shall not be less than the heights above ground level presented in Table 17 (ground level basis of 1422 feet above sea level): {Title 129, Chapters 4 and 19}

**Table 17. Stack Height Requirements**

<b>Equipment Description</b>	<b>SV #</b>	<b>Minimum Stack Height (m)</b>
Corn Receiving (East Truck Unloading Pits #1 and #2)	1	50
Corn Receiving (West Truck Unloading Pits #3 and #4)	2	50
Coal-fired boiler # 1 and 2	COGEN1	90
Germ Cooler # 1, 2, and 3	9	65
Germ Cooler # 4	12	65
Gluten Cooler # 1 and 2	17	65
Gluten Recycle	44	27.99
Corn Cleaner	4	43.71
Millhouse/Feedhouse	5	41.68
Starch Dryer # 1	6	65
Germ Dryer # 1-3	7	65
Fluidized Bed Germ Dryer #1	8	65
Gluten Flash Dryer # 1	16	65
Gluten Flash Dryer # 2	18	65
Biogas Flare	41	25
Fiber Dewatering	43	40
Starch Dryer #2	45	33.52
Boiler #5	98	38.25
Rotary Car Dumper/Truck Dump Building Unit 1	COGEN2	25
Rotary Car Dumper/Truck Dump Building Unit 2	COGEN3	25
Coal Storage Dome/Reclaim Tunnel	COGEN4	25
Crusher Tower	COGEN5	25
Powerhouse Bunker Bay	COGEN6	40
Fly Ash Transfer/Storage Unit 1	COGEN7	25
Fly Ash Transfer/Storage Unit 2	COGEN8	25
Bottom Ash Collection Unit 1	COGEN9	15
Bottom Ash Collection Unit 2	COGEN10	15
Bottom Ash Transfer/Storage Unit 1	COGEN11	20
Bottom Ash Transfer/Storage Unit 2	COGEN12	20

<b>Equipment Description</b>	<b>SV #</b>	<b>Minimum Stack Height (m)</b>
Limestone Storage Unit 1	COGEN13	25
Limestone Storage Unit 2	COGEN14	25
Limestone Transfer Unit 1	COGEN15	20
Limestone Transfer Unit 2	COGEN16	20
EU9-17-18	COGEN17	10
EU9-19-22	COGEN19	13

- (2) The source shall sufficiently restrict public access to the facility at the ambient air boundary relied upon in the modeling analysis for the NAAQS compliance demonstration. An ambient air restriction plan detailing the measures for restricting public access (such as fencing) shall be submitted to the Department within 120 days of permit issuance.
  - (3) A site survey or similar documentation demonstrating compliance with the stack height limitations per Condition XIII.(U)(1) shall be kept on site and readily available to Department representatives within 365 days after the permit issuance date; or for any new or modified emission unit constructed after this date, within 180 days following start-up of the new or modified emission unit.
  - (4) A site survey or similar documentation demonstrating compliance with the restricted public access provisions of Condition XIII.(U)(2) shall be kept on site and readily available to Department representatives within 180 days after the permit issuance date. The site survey or similar documentation shall provide sufficient detail to verify that an ambient air restriction plan has been fully implemented.
- (V) The performance tests required in the permit must be completed and submitted to the Department as follows: {Title 129, Chapter 34, Section 001}
- (1) Unless otherwise specified in this permit, the performance tests shall be conducted while operating at full capacity within 60 days after reaching the maximum capacity but not more than 180 days after the start up of operations.
  - (2) Testing methods shall be from 40 CFR 60 Appendix A, or other method approved by the NDEQ.
  - (3) An emissions testing protocol shall be submitted to the Department at least 45 days prior to testing.
  - (4) The owner or operator of a source shall provide the Department 30 days notice prior to testing to afford the Department an opportunity to have an observer present.
  - (5) The source shall monitor the operating parameters for process and control equipment during the performance testing required in the permit (e.g., production rate, liquid flow rate and pressure differential during testing of the scrubber). The operating parameters shall be submitted with the test results.

- (6) A certified written copy of the test results signed by the person conducting the test shall be provided to the Department within 45 days of completion of the test.
- (W) The following conditions apply to: **MONITORING AND RELATED RECORDKEEPING AND REPORTING REQUIREMENTS**

Records of all limits, measurements, results, inspections, and observations listed in Conditions XIII.(A) through XIII.(V), as required to ensure compliance with this permit shall be maintained. Calculations and records shall be completed no later than the last day of each calendar month through the previous calendar month. Records shall be kept on-site for a minimum of five years, unless otherwise specified in this permit. These records shall be clear and readily accessible to Department representatives and shall include the following:

- (1) Inspection and maintenance records for each baghouse dust collector as identified in, and to demonstrate compliance with, Conditions XIII.(A)(3), (E)(3), (K)(3), (L)(2) and (S)(2). These records shall include the following:
  - (a) Records documenting when routine observations were performed with a description, including operating parameters (e.g., pressure differential readings) and any atypical observations.
  - (b) Records documenting when routine maintenance and preventive actions were performed with a description of the maintenance and/or preventive action conducted.
  - (c) Filter replacement records including number of replaced filters, type, and date of filter installation.
  - (d) Records documenting equipment failures, malfunctions, or other variations, including time of occurrence, remedial action taken, and when corrections were made.
- (2) Inspection and maintenance records each scrubber as identified in, and to demonstrate compliance with, Conditions XIII.(B)(2), (D)(5), (F)(2), (I)(3) and (R)(2). These records shall include the following:
  - (a) Records documenting when routine observations were performed with a description, including operating parameters (e.g., pressure differential readings, scrubbing flow rates) and any atypical observations.
  - (b) Records documenting when routine maintenance and preventive actions were performed with a description of the maintenance and/or preventive action performed.
  - (c) Records documenting equipment failures, malfunctions, or other variations, including time of occurrence, remedial action taken, and when corrections were made.

- (3) As designated in Title 129, Chapter 18, Section 001.62, Volatile Organic Liquid Storage Vessels (including petroleum storage vessels) – Subpart Kb, Reporting and Recordkeeping Requirements {40 CFR 60.115b}, records to demonstrate compliance with Condition XIII.(G)(2).
- (4) Operation and maintenance record for the vapor recovery system, flare, and safety device or flame monitoring system for the liquid product loadout stations, to demonstrate compliance with Condition XIII.(H)(2), shall include the following:
  - (a) Records documenting when routine maintenance and preventive actions were conducted with a description of the maintenance and/or preventive action conducted.
  - (b) Records documenting equipment failures, malfunctions, or other variations, including time of occurrence, remedial action taken, and when corrections were made.
- (5) The date when the burner in boiler #1 was replaced, and the manufacturer's documentation of the replacement burner to demonstrate compliance with Condition XIII.(J)(2).
- (6) As designated in Title 129, Chapter 18, Section 001.22, Industrial-Commercial-Institutional Steam Generating Units –Subpart Db, Recordkeeping Requirements {40 CFR 60.49b}, records to demonstrate compliance with Conditions XIII.(J)(4) and (K)(7).
- (7) Fuel receipts for natural gas, diesel, coal, petroleum coke, and TDF from the suppliers to demonstrate compliance with Conditions XIII.(J)(4)(f), (K)(7)(f), and (P)(2).
- (8) As designated in Title 129, Chapter 28, Section 001.90, Commercial, Industrial, and Institutional Boilers and Process Heaters – Subpart DDDDD, Recordkeeping Requirements {40 CFR 63.7555}, records to demonstrate compliance with Conditions XIII.(J)(5), (J)(6) and (K)(8).
- (9) Operation and maintenance records for each cooling tower, to demonstrate compliance with Condition XIII.(M)(1), shall include the following:
  - (a) Records documenting when routine maintenance and preventive actions were performed with a description of the maintenance and/or preventive action performed.
  - (b) Records documenting equipment failures, malfunctions, or other variations, including time of occurrence, remedial action taken, and when corrections were made.
- (10) Manufacturer's drift loss guarantee to demonstrate compliance with Condition XIII.(M)(2). This record shall be kept for the life of the equipment.

- (11) TDS concentration in cooling water for each sampling event to demonstrate compliance with Condition XIII.(M)(3).
- (12) As designated in Title 129, Chapter 18, Section 001.14, Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry – Subpart VV, Recordkeeping Requirements {40 CFR 60.486}, records to demonstrate compliance with Condition XIII.(N)(1).
- (13) Records documenting use of fugitive dust control measures on haul roads, such as when water spraying is applied, to demonstrate compliance with Conditions X. and XIII.(O)(1)(a).
- (14) Record of haul road visible emissions checks taken daily during operation and a description of corrective action taken to demonstrate compliance with Condition XIII.(O)(1)(b).
- (15) Hours of operation for each piece of emergency equipment for each calendar month and for each period of twelve (12) consecutive calendar months to show compliance with Condition XIII.(P)(1).
- (16) Hours of operation for the biogas flare for each calendar month and for each period of twelve (12) consecutive calendar months to show compliance with Condition XIII.(Q)(2).
- (17) Operation and maintenance records for the wastewater treatment tanks and biogas flare to demonstrate compliance with Condition XIII.(Q)(4), which shall include the following:
  - (a) Records documenting when routine maintenance and preventive actions were performed with a description of the maintenance and/or preventive action performed.
  - (b) Records documenting equipment failures, malfunctions, or other variations, including time of occurrence, remedial action taken, and when corrections were made.
- (18) As designated in Title 129, Chapter 28, Section 001.78, National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing – Subpart FFFF, Recordkeeping Requirements {40 CFR 63.2430}, records to demonstrate compliance with Condition XIII.(T).
- (19) Site survey or similar documentation demonstrating compliance with the stack height limitations per Condition XIII.(U)(1) and the restricted public access provisions per Condition XIII.(U)(2). These records shall be kept for the life of the equipment.
- (20) Calibration records for all operating parameter monitoring equipment.
- (21) Copies of all notifications, reports, plans, and test results submitted to the Department.

- (22) Manufacturer's operation and maintenance manual, or its equivalent regarding design, installation, operation, and maintenance for all permitted equipment. These records shall be kept for the life of the equipment.

The undersigned issues this document on behalf of the Director in accordance with Title 129 – Nebraska Air Quality Regulations.

8/4/06

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Date

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Shelley Kaderly  
Air Quality Division Administrator

## **FACT SHEET**

Archer Daniels Midland Company  
3000 East 8<sup>th</sup> Street  
Columbus, Nebraska 68601-9073

August 4, 2006

### **DESCRIPTION OF THE FACILITY OR ACTIVITY:**

Archer Daniels Midland Company (ADM) owns and operates a wet corn milling and ethanol production plant located at 3000 East 8<sup>th</sup> Street in Columbus, Nebraska. This plant, owned by Minnesota Corn Processors, LLC until 2002, was constructed in 1991. The plant operates under primary Standard Industrial Classification (SIC) Code 2046 (Wet Corn milling) and secondary SIC 2869 (Industrial Organic Chemicals).

The facility consists of the following major production steps/areas:

- grain receiving, storing, and wet corn milling;
- germ, gluten, starch separation;
- germ, gluten, and starch drying;
- fermentation and distillation;
- ethanol and denaturant storage and loadout;
- sweeteners production;
- steam generation;
- wastewater treatment; and
- emergency power generation.

This permit is intended to address several outstanding regulatory requirements, as well as to permit expansion of the existing ethanol plant. First, this permit addresses requirements contained in a Consent Decree negotiated under United States v. ADM (C.D. IL, NO. 03-CV-2066), which was filed with the U.S. District Court – Central District of Illinois on August 21, 2003. In addition, the facility is planning an expansion of their operations, which will increase the capacity of this facility from 100 million gallons of ethanol per year to 120 million gallons of ethanol per year. Finally, this permit addresses the requirements and associated injunctive relief related to compliance with Title 129, Chapter 27, Section 002 (Best Available Control Technology requirements for sources of hazardous air pollutants) of the Nebraska Administrative Code.

The major regulatory actions required by the Consent Decree which are addressed in this permit include:

- submittal of a PSD permit application to identify and correct any non-compliance with the National Ambient Air Quality Standards (NAAQS);
- 95% VOC control (or control to 20 ppmvd) on the Germ Dryers, the Millhouse Vent, the Distillation Scrubber Vent, the Fermentation Vent, and the Stillage MR Vents;
- identification and inclusion/revision of CO and VOC emission limits for existing sources; and
- modification and optimization of existing control devices and emission units to reduce emissions.

Concerning the plant expansion, this permit authorizes the construction and modification of the following emission units:



- construction of two (2) new 600,000 lb/hr (~768 MMBtu/hr) solid fuel-fired, circulating fluidized bed steam generating units;
- construction of associated support and control equipment (coal, fly ash, and lime handling equipment and new cooling towers);
- construction of one (1) new 250 MMBtu/hr natural gas-fired steam generating unit (Unit #5);
- construction of one (1) new rail ethanol loadout station controlled by the existing loadout flare;
- construction of one (1) new 105,000 gallon floating-roof denaturant storage tank;
- modification of the existing Gluten Flash Dryer #2 to increase capacity from 26 MMBtu/hr to 65 MMBtu/hr;
- modification of the existing Fluid Bed Germ Dryer to increase capacity from 35 MMBtu/hr to 55 MMBtu/hr;
- installation of a new wet scrubber to control VOC and SO<sub>2</sub> emissions from the Fluid Bed Germ Dryer;
- modification of the fermentation vessel capacity from 5 million gallons to 6 million gallons;
- elimination of the plant's original throughput limit and grain-haul truck receiving limit (these limits were taken previously to make PSD review not applicable, and to ensure compliance with the NAAQS for PM<sub>10</sub>); and
- increase in the flowrate to the existing cooling towers.

ADM was issued a Prevention of Significant Deterioration of Air Quality (PSD) permit for this source on July 12, 1995 that superseded all previous permits. Since receipt of that permit, the following construction permits have been issued:

- December 23, 1999 - permit issued for the construction of starch receiving, storage and drying operations;
- July 3, 2001 - permit issued for the construction and modification of corn receiving operations to allow receipt of corn by rail, and to increase the corn receiving, storage, and processing limits;
- March 31, 2003 - permit issued for expansion of facility operations to increase the overall ethanol production capacity from 80,000,000 gallons per year to 100,000,000 gallons per year; and
- April 15, 2003 - permit modification to the July 12, 1995 permit was issued which allowed ADM to stage additional delivery trucks on ADM property.

ADM is currently planning the addition of a dry mill ethanol plant at this location. This project is expected to be permitted in 2006, and all applicable requirements for that project will be addressed in a separate permit.

ADM received their initial Class I Operating permit on February 17, 2005. This permit consolidates all previous construction permit requirements (prior to issue date of the operating permit for the source into one permit.

Acronyms and abbreviations used in this permit and fact sheet are:

Ambient Air Quality Standards (AAQS)

Ammonia (NH<sub>3</sub>)

Best Available Control Technology (BACT)

Circulating Fluidized Bed Boiler (CFB Boiler)

Carbon Monoxide (CO)

Chemical Abstract Service Number (CAS #)

Code of Federal Regulations (CFR)

Compilation of Air Pollutant Emission Factors, Volume I, Stationary Point and Area Sources (AP-42)

Compliance Assurance Monitoring (CAM)  
Construction Permit (CP)  
Continuous Emissions Monitor System (CEMs)  
Continuous Opacity Monitoring System (COMS)  
Factor Information and Retrieval System (FIRE)  
Hazardous Air Pollutant (HAP)  
Hydrochloric acid (HCl)  
Hydrofluoric acid (HF)  
Hydrogen Sulfide (H<sub>2</sub>S)  
Internal Floating Roof (IFR)  
Lead Compounds (Pb)  
Lowest Achievable Emission Rate (LAER)  
Maximum Achievable Control Technology (MACT)  
Mercury Compounds (Hg)  
Maximum Achievable Control Technology (MACT)  
Million British Thermal Units (MMBtu)  
Mechanical Recompression (MR)  
National Ambient Air Quality Standards (NAAQS)  
New Source Performance Standards (NSPS)  
Nitrogen Oxides (NO<sub>x</sub>)  
Office of Management and Budget (OMB)  
Operating Permit (OP)  
Particulate Matter (PM)  
Particulate Matter less than or equal to 10 micrometers (PM<sub>10</sub>)  
Parts per million volume, dry basis (ppmvd)  
Pounds per Hour (lbs/hr)  
RACT/BACT/LAER Clearinghouse (RBLC)  
Rotary Vacuum Filter (RVF)  
Prevention of Significant Deterioration (PSD)  
Significant Impact Level (SIL)  
Stack/Vent (SV)  
Sulfur Dioxide (SO<sub>2</sub>)  
Sulfuric Acid (H<sub>2</sub>SO<sub>4</sub>)  
Total Dissolved Solids (TDS)  
Total Reduced Sulfur (TRS)  
Volatile Organic Compounds (VOC)

**TYPE AND QUANTITY OF AIR CONTAMINANT EMISSIONS ANTICIPATED:**

The modified wet mill and ethanol plant will generate emissions of several air pollutants, including nitrogen oxides (NO<sub>x</sub>), carbon monoxide (CO), sulfur oxides (SO<sub>x</sub>) total particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to 10 micrometers (PM<sub>10</sub>), volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). The primary emission sources at the facility will be from the following equipment/processes:

<b>Equipment/Process</b>	<b>Pollutants</b>
Grain receiving, storing, and milling	PM and PM <sub>10</sub>
Fermentation and distillation	VOC and HAPs
Ethanol loadout	VOC and HAPs
Product drying (germ, gluten)	NO <sub>x</sub> , CO, VOC, HAP, PM, and PM <sub>10</sub> , and SO <sub>2</sub>
Steam generation	NO <sub>x</sub> , CO, VOC, HAP, PM, PM <sub>10</sub> , and SO <sub>2</sub>
Coal, limestone, and ash handling	PM and PM <sub>10</sub>
Truck traffic fugitives	PM and PM <sub>10</sub>
Equipment leaks	VOC and HAPs
Cooling towers	PM and PM <sub>10</sub>
Wastewater treatment	NO <sub>x</sub> , CO, VOC, PM, PM <sub>10</sub> , and SO <sub>2</sub>
Emergency equipment	NO <sub>x</sub> , CO, VOC, PM, PM <sub>10</sub> , and SO <sub>2</sub>

Various pieces of control equipment have been designed into the facility to reduce potential emissions. These include dust collectors on corn, coal, limestone, and ash handling and storage equipment; scrubbers on fermentation and distillation and product drying operations; product recovery cyclones, a flare to control VOC emissions from product loadout; a flare to control emissions from wastewater treatment; limestone and ammonia injection and fabric filters to control SO<sub>2</sub>, NO<sub>x</sub>, and particulate emissions from coal combustion, and paved plant haul roads to minimize fugitive emissions.

#### **Grain Receiving, Handling and Storage {Condition XIII.(A)}**

The grain receiving system consists of four truck dumps (EU1-1 and EU1-2), one rail dump and associated conveying equipment (EU14-71) that transfer grain into any of eight truck side storage silos (EU1-54 thru EU1-61), nine rail side silos, each controlled by two Bin vents (EU14-72 through EU14-89), or to the corn cleaning process (EU2-3 and EU2-4). The truck dumps and conveying transfer points are serviced by Corn Receiving East and West baghouses (SV-1 and SV-2). The rail dump and associated conveying transfer points are serviced by the Rail Corn Storage baghouse (SV-71). The eight truck side silos have one vent, each which will be controlled by new baghouses (SV's 54-61). The nine rail side silos have two vents each, which are controlled by individual dust collectors (SV's 72-89). The rail side silos have an aeration system (EU14-105 and EU14-106) with powered vents that will be serviced by the new Rail Corn silo aeration baghouses #1 and #2 (SV-105 and SV-106).

Grain is transferred to the processing area and passes through a series of cleaning equipment, which is serviced by the Corn Cleaner baghouse (SV-4). The fines from the cleaners and all grain system baghouses are collected in one of two fines bins, which are serviced by the Corn Cleaner Bin Vent baghouse (SV-3). The fines are transferred to the processing area to be added to feed products. The transferred fines are collected in the Fines Transfer baghouse (SV-42). ADM estimates that there will be an increase in grain receiving of approximately 7.5 million bushels per year to accommodate the increased ethanol production.

#### **Separations, Dewatering, and Drying Processes {Conditions XIII.(B), (C), (D), and (E)}**

In the first step after receiving, grain is steeped in a dilute solution of sulfurous acid (H<sub>2</sub>SO<sub>3</sub>) and then processed through a series of grinding and separation operations. The vents from several process tanks and from separation processes are collected and are controlled by two millhouse/feedhouse packed tower scrubbers (SV-5). The separation processes result in several intermediate product streams (starch, germ, and gluten) as described below.

The separated fiber is dewatered, combined with heavy steepwater and fines, and piled for shipment as a wet feed product. The feed dewatering process tanks and dewatering equipment vents are collected and discharged through a stack (SV-43).

A portion of the starch is dewatered and dried in steam-heated Starch Dryer #1 (EU4-6) and Starch Dryer #2 (EU4-45). The steam heat is provided by the existing natural gas boilers #1-4 (EU9-38 through EU9-41). The product from these dryers is collected in any of six starch storage bins (EU4-20 through EU4-23, EU4-46, and EU4-47), which are controlled by baghouse bin vents (SV-20 through SV-23, SV-46, and SV-47). The dry starch is loaded into rail cars through a transfer system (EU4-48) that is controlled by the Starch Dryer Loadout baghouse (SV-48). The balance of the starch, that is not dried, is transferred in slurry form to the ethanol plant or the high fructose corn syrup refinery.

The separated germ is dewatered and dried in one of four germ dryers. Steam-heated Germ Dryers 1-3 (EU5-7A through EU5-7C) are serviced by the Germ Dryer Scrubber (SV-7), and are heated by steam from the existing boilers. The fourth germ dryer, the Fluid Bed Germ Dryer (EU5-8), has a Low-NO<sub>x</sub> Burner and a cyclone/scrubber (SV-8). The product from these dryers is collected by Germ Cooling baghouses. The three baghouses controlling EU5-9A, EU5-9B, and EU5-9C are combined into one stack (SV-9). There is a single baghouse (SV-12) controlling EU5-12. The product is then transferred to any of four germ storage bins (EU6-28 through EU6-31), which are controlled by bin vent baghouses (SV-28 through SV-31).

The separated gluten meal is dewatered and dried in one of two natural gas gluten flash dryers (EU6-16 and EU6-18), both controlled by Low-NO<sub>x</sub> Burners, product collection cyclones, and wet contact scrubbers (SV-16 and SV-18). A portion of the dry gluten is recycled for feed conditioning via Gluten Recycle (EU6-44), controlled by a baghouse (SV-44). The remaining product from these dryers is collected in Gluten coolers (EU6-17 and EU6-19), both controlled by baghouses (SV-17 and SV-19). The product is then transferred into any of four gluten storage bins (EU5-24 through EU5-27), which are controlled by bin vent baghouses (SV-24 through SV-27).

The liquid slurry created from the separation processes is dewatered through the use of three gluten rotary vacuum filters (RVFs) (EU6-66, EU6-67, and EU6-68), which draw the slurry through the use of vacuum applied to a rotating drum. The vapors from this process are collected and vented through the gluten RVF vents (SV-66 through SV-68). The separated steepwater is concentrated by evaporation in two Stillage/Steepwater evaporators (EU12-69 and EU12-70, which vent through SV-69 and SV-70, respectively) and the resultant heavy steepwater is either added to feed products, or stored and shipped as a product. The evaporation and RVF vents (SV-66 through SV-70) are controlled via the aforementioned millhouse/feedhouse scrubber (SV-5).

### **Ethanol and High Fructose Refining Processes {Conditions XIII.(F), (G), (H), and (I)}**

After the separation step, starch slurry is sent to the Ethanol refinery where it is converted into sugar, which is fermented into alcohol and carbon dioxide. The carbon dioxide and process vents from the fermenters are scrubbed by parallel packed tower scrubbers (SV-32 and SV-33). The alcohol is distilled, dehydrated, denatured, and stored for shipment (Tanks TK-01 thru TK-06 and TK-08). The distillation vents are combined and controlled via a third packed tower scrubber (SV-34). The denatured alcohol product (Ethanol) is loaded into trucks and rail cars (EU7-90). The displaced vapors from the loading systems are controlled by the Liquid Product Loadout Flare (SV-90).

Starch slurry is also sent to the High Fructose Syrup refinery where it is converted to sugar, which is further converted to fructose. Fructose syrup is refined using activated carbon, which is regenerated by two carbon furnaces (EU8-35 and EU8-36, rated at 10 MMBtu/hr and 15.9 MMBtu/hr, respectively).

Soda ash is used in the fructose process for pH adjustment and resin regeneration. The soda ash is pneumatically unloaded using a system (EU8-63) that is controlled by a wet contact scrubber (SV-63).

#### **Equipment Leaks {Condition XIII.(N)}**

Equipment leaks are leaks from valves and pumps in light service, gas valves, control valves, flanges, transmitters, and manholes. The company will perform Leak Detection and Repair (LDAR) Program in accordance with NSPS, Subpart VV. {40 CFR 60.480 through 60.489} Emissions are calculated from *Protocol for Leak Emission Estimates*, EPA-453/R-95-017, November 1995. Emissions include fugitive VOC and HAP emissions.

The equipment leaks will be assumed to be anhydrous ethanol process lines for determination of HAP emissions. The individual HAP mass fractions of the VOC from the equipment leaks are derived from the stack testing of the fermentation scrubber or testing of the anhydrous ethanol.

#### **Haul Roads {Condition XIII.(O)}**

Haul road emissions consist of truck traffic on the paved roads as part of the receiving of raw materials (denaturant, grain) or shipping of final products (denatured ethanol, gluten, germ). The haul roads must be in compliance with Condition X of the permit. Fugitive dust emissions from traffic on these roads have been calculated using a site-specific emission factor based on AP-42 and source supplied silt loading factor, and typical characteristics for paved roads.

#### **Emergency Equipment {Condition XIII.(P)}**

The emergency equipment consists of four diesel-fired fire pump engines (EU-95, EU-96, EU-107, EU-108), one 10 hp diesel-fired engine (EU-97) and one 68 hp diesel-fired engine (EU-99), all limited to 400 hours per year of operation each. The engines are limited to the expected number of operating hours during non-emergency periods (maintenance and testing). If there is an emergency requiring the fire water-pumps, it is expected that the rest of the facility will be shut down. Since the emergency equipment is diesel fired, a diesel storage tank will be installed. The tank will hold 250 gallons or less. Due to the small tank size, low volume throughput, and low vapor pressure of diesel fuel, the VOC emissions associated with the diesel fuel storage are expected to be negligible.

#### **Utility Processes {Conditions XIII.(J), (K), and (L)}**

The separations, drying, and refining processes are supported by several utility systems.

Steam is currently produced from the four existing natural gas boilers (EU9-38 through EU9-41), which are controlled, by Low-NO<sub>x</sub> burners and discharge into three stacks (SV's 38-40). Boilers #3 (EU9-40) and Boiler #4 (EU-41) share a common stack (SV-40). A proposed, fifth natural gas boiler (EU9-98) with similar controls will also support steam production and will discharge into a single stack (SV-98). The natural gas boilers will become secondary support units when the two proposed coal boilers (EU9-1A and EU9-1B) become operational. The emissions from the coal boilers are controlled by limestone addition, ammonia injection (SNCR), and baghouses. The coal boilers discharge into a common stack (SV-COGEN1) through separate flues. The coal unloading, crushing, and storage equipment (EU9-2 through EU9-6) are controlled by five baghouses (COGEN2-6). The boiler ash recovery, transfer and storage systems (EU9-7 through EU9-12) are controlled by six baghouses (SV's COGEN7-12). The limestone storage and transfer systems (EU9-13 through EU9-16) are controlled by four baghouses (SV's COGEN13-16). The coal steam plant is serviced by two cooling towers, one with two cells (EU9-17-18) and one with four cells (EU9-19-22).

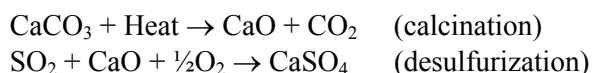
The proposed coal-fired boilers (EU9-1A and EU9-1B) are two identical 768 million Btu per hour (MMBtu/hr), solid fuel-fired steam generating units that will utilize circulating fluidized bed (CFB) boiler technology to burn coal, petroleum coke, biomass (waste or by-products from the grain milling operations including wet gluten feed, DDGS, corn cobs, etc.), and tire-derived fuel (TDF). The CFB technology offers the flexibility of burning the various solid fuels (coal, biomass, petroleum coke, and tires) with low emission rates. The CFB boiler technology provides inherent control of SO<sub>2</sub> and NO<sub>x</sub> by:

- Operating at low combustion temperatures with staged combustion for low thermal NO<sub>x</sub> generation; and
- In-bed injection of limestone sorbent for reduction of SO<sub>2</sub> concentrations for protecting internal surfaces from sulfide corrosion

In the furnace section of a CFB boiler, a mixture of fuel, limestone, char, and ash is suspended or “fluidized” in an upwardly flowing gas stream. Although the fuel particles and limestone are solids, the combination of fuel particles, limestone and combustion air exhibit fluid-like properties. Combustion air forced in at the bottom of the furnace keeps the bed in a constantly upward moving flow. At the top of the furnace, relatively large entrained particles are separated from smaller ash particles and combustion gases, and then are returned to the furnace until combustion is complete. It is due to the circulating nature of the fluidized bed that this combustion technology is referred to as a circulating fluidized bed boiler.

Combustion takes place within the furnace “bed” with high furnace heat transfer rates while maintaining low combustion temperatures ranging from 1,500 to 1,650°F. Because thermal NO<sub>x</sub> formation is predominately a high temperature process occurring at temperatures in excess of 2,000°F, the lower operating temperature of the CFB boiler technology significantly reduces thermal NO<sub>x</sub> production. Additional NO<sub>x</sub> control will be provided by a selective non-catalytic reduction (SNCR) system, which injects ammonia (NH<sub>3</sub>) or urea (which decomposes to NH<sub>3</sub>) into the appropriate high temperature region of the furnace/boiler for conversion of NO<sub>x</sub> to N<sub>2</sub> and H<sub>2</sub>O.

The addition of limestone to the fluidized bed allows for fuel sulfur removal to occur directly in the boiler, which reduces the corrosion rate of the furnace metal surfaces. The limestone is calcined in the fluid bed forming calcium oxide. The calcium oxide (CaO) reacts with sulfur dioxide (formed from sulfur in the fuel) to form calcium sulfate (CaSO<sub>4</sub>). The key reactions are as follows:



Depending upon the calcium to sulfur (Ca:S) ratio within the bed, SO<sub>2</sub> removal rates of 90 to 95 percent can be achieved. Similar high reduction levels will be achieved for sulfuric acid and fluorides.

Criteria pollutant emissions from firing alternative fuel blends (tire-derived fuel, biomass, and petroleum coke) have not been fully characterized in AP-42, or other available literature. Several studies have been done on burning tire-derived fuel (TDF) in combination with coal, and while no universally-applicable emission factors are available for such blends, the general trend in the literature is that higher SO<sub>2</sub> and CO emissions are possible, with lower emissions of all other pollutants (including metal and organic HAPs). Petroleum coke has a high heating value and high sulfur content, but has very low ash and mercury contents and is expected to have lower organic and metal HAP emissions than coal. Biomass fuels generally have lower sulfur and ash contents than coal, lower metal HAP and HCl and HF emissions, with some possible increase in organic HAP emissions relative to coal, petroleum coke, or TDF.

The U.S. Environmental Protection Agency (USEPA) has determined and imposed Maximum Achievable Control Technology (MACT) limits for emissions of organic and inorganic HAP from solid-fuel fired industrial boilers. Specifically, limits are imposed to regulate emissions of mercury, hydrogen chloride, trace metals, and trace organic compounds from the combustion of solid fuels including coal, petcoke, TDF, and biomass. In the case of the trace metals and trace organics, the MACT regulation imposes surrogate limits, which USEPA has determined are effective in limiting emissions of HAP. These surrogate limits impose strict standards on the emissions of fine particulate matter and they effectively regulate the combustion process in a way that helps ensure organic HAP are destroyed in the furnace of the boilers. The new CFB boilers at ADM's Columbus plant are designed to meet these strict MACT emissions standards for all fuels and fuel blends, and the boilers must comply with these standards once they become operational.

PSD-BACT emission limits were used to calculate emissions for all PSD-regulated pollutants, and HCl and mercury emissions are based on the limits in the boiler NESHAP (see Title 129, Chapter 28 discussion below). Emissions of all other HAPs were calculated using AP-42 emissions factors for coal combustions. Criteria pollutant emissions from the CFB boilers will be monitored using required CEMS for NO<sub>x</sub>, SO<sub>2</sub>, and CO. Stack testing will be required for PM/PM<sub>10</sub>, VOC, as well as for F (as HF), H<sub>2</sub>SO<sub>4</sub>, HCl, Hg, and Pb. See Appendix A for detailed emissions calculations for the CFB boilers.

### **Cooling Towers and Wastewater {Conditions XIII.(M), XIII.(Q), and XIII.(S)}**

Process cooling water for the ethanol and fructose plants are supplied by a six cell cooling tower for the ethanol plant (EU13-E1-E6) and a three cell cooling tower for the fructose plant (EU13-F1-F3). Well water is softened via the cold lime softening process. The powdered lime is unloaded pneumatically into a storage silo (EU13-62) that is controlled by a vent baghouse (SV-62). Process wastewater streams are treated in anaerobic treatment basins with polishing via aerated basins. The methane gas produced is collected and combusted in either the gluten dryers or a biogas flare (EU10-41).

### **Emissions Summary**

Potential emissions of criteria pollutants and HAPs from all operations occurring at the modified facility were estimated using a combination of vendor guarantees, process design data, engineering calculations, emission factors from EPA's Compilation of Air Pollutant Emission Factors, 5<sup>th</sup> Edition, Volume 1 (AP-42), and material safety data sheet (MSDS) information. Potential emissions from the existing and modified facility are shown in Table 1 along with the net change in potential emission. Detailed emissions calculations are presented in Appendix A.

**Table 1. Source-wide Emissions Summary**

<b>Regulated Pollutant</b>	<b>Existing Potential Emissions<sup>a</sup> (tons/year)</b>	<b>New Potential Emissions (tons/year)</b>	<b>Change in Potential Emissions (tons/year)</b>
Particulate Matter (PM)	427	589	162
PM smaller than or equal to 10 microns (PM <sub>10</sub> )	356	441	85
Oxides of Sulfur (SO <sub>x</sub> )	847	1,569	722
Oxides of Nitrogen (NO <sub>x</sub> )	265	843	578
Carbon Monoxide (CO)	484	1,224	740
Volatile Organic Compounds (VOC)	1,018	650	- 368
Sulfuric Acid (H <sub>2</sub> SO <sub>4</sub> )		67.3	67.3
Hazardous Air Pollutants (HAP):			
Acetaldehyde (CAS# 75070)		0.24	0.24
Arsenic Compounds	0.004	0.16	0.16
Benzene (CAS# 71432)	0.008	0.55	0.55
Benzyl chloride (CAS# 100447)		0.28	0.28
Cyanide Compounds		0.99	0.99
Ethylene Dichloride (CAS# 107062)		0.16	0.16
Formaldehyde (CAS# 50000)	0.29	0.48	0.19
Hexane (CAS# 110543)	6.99	9.41	2.42
Hydrochloric Acid (CAS# 7647010)	0.0006	134.6	134.6
Hydrofluoric Acid (CAS# 7664393)		8.07	8.07
Isophorone (CAS# 78591)		0.23	0.23
Lead Compounds	0.01	1.35	1.34
Manganese Compounds	0.01	0.20	0.19
Methyl Chloride (CAS# 74873)		0.21	0.21
Selenium compounds	0.02	0.52	0.50
Toluene (CAS# 108883)	0.01	0.16	0.15
Miscellaneous HAPs <sup>b</sup>	0.13	1.29	1.16
<b>Total HAPs</b>	<b>8.74</b>	<b>158.9</b>	<b>150.2</b>

<sup>a</sup> The existing emissions are based on the Fact Sheet for the Class I Operating Permit issued 2-17-05.

<sup>b</sup> Miscellaneous HAPs include all HAPs emitted at less than 0.1 ton per year as follows: 1,2,4-Trimethyl benzene (CAS # 120821), 1,3-Butadiene (CAS # 106990), 2,2,4-Trimethyl pentane (CAS # 540841), 2,4-Dinitrotoluene (CAS # 121142), 2-Chloroacetophenone (CAS # 532274), Acetophenone (CAS # 98862), Acrolein (CAS # 107028), Antimony Compounds, Beryllium Compounds, Bis(2-ethylhexyl)phthalate (CAS # 117817), Bromoform (CAS # 75252), Cadmium Compounds, Carbon Disulfide (CAS # 75150), Chlorobenzene (CAS # 108907), Chloroform (CAS # 67663), Chromium Compounds, Cobalt Compounds, Cumene (CAS # 98828), Dichlorobenzene (CAS # 25321226), Dimethyl Sulfate (CAS # 77781), Ethyl benzene (CAS # 100414), Ethyl chloride (CAS # 75003), Ethylene Dibromide (CAS # 106934), Mercury Compounds, Methanol (CAS # 67561), Methyl Bromide (CAS # 74839), Methyl Chloroform (CAS # 71556), Methyl Ethyl Ketone (CAS # 78933), Methyl Hydrazine (CAS # 60344), Methyl Methacrylate (CAS # 80626), Methyl tert Butyl Ether (CAS # 1634044), Methylene Chloride (CAS # 75092), Naphthalene (CAS # 91203), Nickel Compounds, Phenol (CAS # 108952), Polycyclic Organic Hydrocarbons (POM), Propionaldehyde (CAS # 123386), Styrene (CAS # 100425), Tetrachloroethylene (CAS # 127184), Vinyl Acetate (CAS # 108054), and Xylene (CAS # 1330207).



## **APPLICABLE REQUIREMENTS AND VARIANCES OR ALTERNATIVES TO REQUIRED STANDARDS:**

### **Consent Decree**

On August 21, 2003, a Consent Decree negotiated under United States v. ADM (C.D. IL, NO. 03-CV-2066), was filed with the U.S. District Court – Central District of Illinois. This Consent Decree required several actions from ADM, including the submittal of a revised PSD application for this facility. This submittal was received by the Department on December 15, 2003 and is covered under this permit. In addition, the Consent Decree contained specific requirements on existing emission units, as well as requiring the source to reduce emissions over time by installing various pieces of control equipment, and by optimizing the performance of existing control equipment.

This permit includes the following revisions, which address the specific control requirements contained within the Consent Decree:

- optimization of the scrubber and establishment of a new PM emissions limit (3.03 lb/hr) for Starch Dryer #1;
- submittal of a road silt management plan for the facility (this plan was submitted as part of the application);
- establishment of revised emission limits for Germ Dryers 1-3 (95% VOC control or 20 ppmvd VOC), the Fluidized Bed Germ Dryer (1.5 lb/hr VOC and 4.02 lb/hr CO), Gluten Flash Dryer #1 (22.8 lb/hr VOC and 15.2 lb/hr CO), and Gluten Flash Dryer #2 (22.2 lb/hr VOC and 4.74 lb/hr CO);
- routing of the Stillage/Steepwater evaporator vents (SV-69 and SV-70) and the Gluten RVF Vents (SV 66-68) to the millhouse scrubber (these units were previously uncontrolled) and 95% control of VOC, or a 20 ppmvd VOC emission limit;
- routing of the distillation operation emissions and non-condensable gas stream to the Fermentation/Distillation scrubber system (SV-32, SV-33, and SV-34) with a VOC limit of 13.5 (lb/hr), which represents greater than 95% control; and
- modification of Boiler #1 to replace the existing burner with a low-NO<sub>x</sub> burner capable of meeting a NO<sub>x</sub> emission limit of 0.06 lb/MMBtu.

As noted above, the CD also requires ADM to install or optimize controls or other mitigation measures to support the NAAQS and increment compliance demonstration, and to use current information to establish more accurate emissions limits for CO and VOC from certain sources. This permit includes the following conditions, which address these goals:

- establishment of revised PM<sub>10</sub>, CO, and VOC emission limits for the Carbon Furnaces 1 and 2;
- increased stack height requirements for several existing stacks; and
- establishment of a VOC emission limit for the Fiber Dewatering process.

### **Title 129, Chapter 4 -National Ambient Air Quality Standards (NAAQS)**

The potential hourly emissions of PM<sub>10</sub>, NO<sub>x</sub>, CO, and SO<sub>x</sub> from the proposed facility modification exceed the threshold for requiring modeling to show compliance with the applicable 24-hour and annual PM<sub>10</sub> NAAQS, the 1-hour and 8-hour CO NAAQS, the 3-hour and 24-hour SO<sub>2</sub> NAAQS, and the annual NO<sub>2</sub> NAAQS. The air quality analyses adequately demonstrate compliance with applicable NAAQS for NO<sub>x</sub>, CO, and SO<sub>x</sub>. The modeling predicted violations to the PM<sub>10</sub> 24-hour and annual NAAQS, however a receptor significance analysis demonstrates that ADM does not cause or contribute significantly to the modeled violations. Additional information is provided in the “PSD Air Quality Impact Analysis”

beginning on Page 18. Per March 21, 2005, Department policy, PM<sub>10</sub> emissions from haul roads were not included in PM<sub>10</sub> modeling since the source implements a fugitive dust control plan designed to minimize emissions from haul roads. To ensure that assumptions used in the modeling remain valid, the facility will have to meet stack height requirements for the various point sources (e.g., dryers, baghouses, boilers, cooling tower), to restrict public access to the facility (e.g., installing a fence in accordance with NDEQ guidelines or implementing other equivalent public access restrictions), to conduct best management practices for maintenance of the haul roads, and to conduct performance testing to verify emissions from major point sources. If the results of the testing are significantly higher than the corresponding values used in the modeling, then the facility may need to remodel to show compliance with the NAAQS. The Department used the Dry Mill application from ADM for this modeling analysis, which includes all emission points from the Coal Boiler project and the Dry Mill project, thus making the modeling review the most conservative approach available. Table 2 presents the results of the NAAQS modeling analysis for the ADM Columbus facility.

**Table 2. NAAQS Modeling Results**

<b>NAAQS Standard</b>	<b>NAAQS limit (ug/m<sup>3</sup>)</b>	<b>Modeled value* (ug/m<sup>3</sup>)</b>	<b>Plant's value (ug/m<sup>3</sup>)</b>	<b>Background impact (ug/m<sup>3</sup>)</b>
24-hr PM <sub>10</sub>	150	498.6	438.6	60
Annual PM <sub>10</sub>	50	119.6	94.6	25
Annual NO <sub>2</sub>	100	27.2	12.2	15
1-hr CO	40,000	7,738.6	168.6	7570
8-hr CO	10,000	2,397.3	67.3	2330
3-hr SO <sub>2</sub>	1300	833.7	713.7	120
24-hr SO <sub>2</sub>	365	330.1	282.1	48
Annual SO <sub>2</sub>	80	48.5	36.5	12

\*Modeled value is the total of the plant's modeled emission rate plus the background impact.

## **Title 129, Chapter 17 – Construction Permit Requirements**

A construction permit modification is required for this facility modification because this construction project has a net increase in emissions at the site greater than the threshold levels identified in Title 129, Chapter 17, Section 001.01 for PM<sub>10</sub>, SO<sub>x</sub> (SO<sub>2</sub> and/or SO<sub>3</sub>), NO<sub>x</sub>, CO, VOC and HAPs. The thresholds are shown in Table 3 below.

**Table 3. Construction Permit Thresholds**

<b>Pollutant</b>	<b>Threshold</b>
PM <sub>10</sub>	15 tons/yr
SO <sub>x</sub> (SO <sub>2</sub> and/or SO <sub>3</sub> )	40 tons/yr
NO <sub>x</sub>	40 tons/yr
CO	50 tons/yr
VOC	40 tons/yr
Individual HAP	2.5 tons/yr
Total combined HAPs	10 tons/yr

## **Title 129, Chapter 18 - New Source Performance Standards (NSPS)**

Subpart A – General Provisions: NSPS Subpart A, adopted by reference in Title 129, Chapter 18, Section 001.01, applies to those units covered by the specific NSPS as discussed below. The permittee is required to submit notification of the date construction commenced postmarked no later than 30 days after such date (40 CFR 60.7(a)(1)), notification of the anticipated date of initial startup of the equipment

postmarked not more than 60 days nor less than 30 days prior to such date (40 CFR 60.7(a)(2)), and notification of the actual date of initial start up of the equipment postmarked within 15 days after such date (40 CFR 60.7(a)(3)).

Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units:

This subpart, adopted by reference in Title 129, Chapter 18, Section 001.22, applies to steam generating units with a design rate greater than 100 MMBtu/hr, installed after June 19, 1984. Therefore, this rule applies to the existing natural gas boilers #1 thru #4, the new CFB Boilers, and the new natural-gas fired Boiler #5 because they each have heat input ratings greater than 100 million Btu per hour. Subpart Db requirements include emission limits for NO<sub>x</sub> from the natural gas boilers of 0.1 pounds per million Btu, for the CFB boilers of 0.20 pounds per million Btu, requires that they monitor emissions from each boiler to determine continued compliance with this limit, and requires recordkeeping and reporting. The CFB boilers also have PM, SO<sub>2</sub>, and opacity limits under the rule. These boilers will be equipped with continuous emissions monitoring systems (CEMs) to show compliance with this NSPS.

Subpart DD – Standards of Performance for Grain Elevators: This subpart, adopted by reference in Title 129, Chapter 18, Section 001.19, applies to grain terminal elevators with a capacity over 2.5 million bushels, and grain storage elevators with a capacity over 1 million bushels installed after August 3, 1978. The capacity of this plant at initial construction was 405,000 bushels, and was increased to 985,000 bushels under the permit issued July 12, 1995. In 2001, a permit was issued to allow construction of a new railcar unloading operation and additional grain storage capacity, which brought the facility total to over 1,000,000 bushels. Therefore, this rule applies to the grain handling operations installed as part of the 2001 project, including the corn cleaner (EU2-4) and the rail corn receiving, storage, and handling operations (EU14-71), since the permanent grain storage capacity was greater than 1 million bushels after the project. Equipment existing prior to the time of that project is not subject to the rule as it is not considered modified or reconstructed as defined under 40 CFR, Part 60.

Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels: This subpart, adopted by reference in Title 129, Chapter 18, Section 001.62, applies to storage tanks constructed after July 23, 1984. This rule applies to the new denaturant tank (TK-08) because it exceeds the minimum capacity threshold of 10,567 gallons and will store volatile organic liquids. This rule also applies to existing storage tanks TK-05 and TK-06 as they also exceed the minimum capacity threshold of 10,567 gallons and store volatile organic liquids. These tanks will be equipped with a vapor mounted wiper as a primary seal, and a rim mounted wiper as a secondary seal. The remainder of the storage tanks at this facility are not subject to this rule due to their small size, vapor pressure, or since they do not store volatile organic liquids. Process tanks TK-01, TK-02, TK-03, and TK-04 are not considered storage tanks, and therefore are not subject to this rule.

Subpart NNN – Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemicals Manufacturing Industry (SOCMI) Distillation Operations: This subpart, adopted by reference in Title 129, Chapter 18, Section 001.61, does not apply to the distillation operation, per EPA's January 24, 2000, letter from Richard Tripp, EPA Region VII to Randy Griffin, Nebraska Air Quality Compliance Supervisor, concerning applicability of 40 CFR 60 to biomass ethanol production. The letter stated that Subpart NNN does not apply to ethanol derived from biomass. Subpart NNN applies to synthetic (chemical reaction of petroleum refining products) processes to produce organic chemicals (including ethanol).

Subpart RRR – Standards of Performance for Volatile Organic Compound (VOC) Emissions from Synthetic Organic Chemicals Manufacturing Industry (SOCMI) Reactor Processes: This subpart, adopted by reference in Title 129, Chapter 18, Section 001.70, does not apply to the fermentation tanks, per EPA's January 24, 2000, letter, from Richard Tripp, EPA Region VII to Randy Griffin, Nebraska Air Quality Compliance Supervisor, concerning applicability of 40 CFR 60 to biomass ethanol production. The letter stated that Subpart RRR does not apply to ethanol derived from biomass. Subpart RRR applies to synthetic (chemical reaction of petroleum refining products) processes to produce organic chemicals (including ethanol).

Subpart VV – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry: This subpart, adopted by reference in Title 129, Chapter 18, Section 001.14, applies to the VOC equipment leaks associated with this plant (a Synthetic Organic Chemical Manufacturing Industry), which were all constructed after the January 5, 1981 applicability date of this rule. This subpart is associated with subpart NNN and RRR, but NNN and RRR are based on how the chemical is produced (biomass versus synthetic), while VV is based on the chemicals produced. Since new organic chemicals are synthesized (process doesn't matter), then all of the associated equipment leaks are subject to this subpart. Associated equipment includes light liquid valves, light liquid pumps, gas valves, control valves, flanges, transmitters, and manholes.

Subpart Y – Standards of Performance for Coal Preparation Plants: This subpart, adopted by reference in Title 129, Chapter 18, Section 001.08, applies to the equipment installed to receive, handle, and process coal for the new CFB boilers because the units will be constructed after October 24, 1974 and will process more than 200 tons of coal per day. However, emission units EU9-2 and EU9-3 (rotary car dumper/truck dump bldgs) are not subject to this standard because they do not meet the definition of a "transfer and loading system" as defined in Subpart Y.

#### **Title 129, Chapter 19 - Prevention of Significant Deterioration (PSD)**

The existing ADM corn wet milling facility is considered a major source for PSD purposes as defined by 40 CFR 52.21. The proposed modifications at this existing major source result in an increase in potential emissions of several regulated pollutants. Table 4 shows potential emissions from the new and modified emission units:

**Table 4. Estimated Potential Emissions from New and Modified Units and PSD Thresholds**

<b>Regulated Pollutant</b>	<b>Potential Emissions (tons/yr)</b>	<b>PSD Significance Threshold (tons/yr)</b>	<b>Subject to PSD Review?</b>
Particulate Matter (PM)	276	25	Yes
PM smaller than or equal to 10 microns (PM <sub>10</sub> )	229	15	Yes
Sulfur Dioxide (SO <sub>2</sub> )	1,667	40	Yes
Oxides of Nitrogen (NO <sub>x</sub> )	596	40	Yes
Carbon Monoxide (CO)	798	100	Yes
Volatile Organic Compounds (VOC)	216	40	Yes
Lead (Pb)	1.35	0.6	Yes
H <sub>2</sub> SO <sub>4</sub> (mist)	67.3	7	Yes
Fluorides	8.1	3	Yes

As the table illustrates, this project will be subject to the requirements of Title 129, Chapter 19 - Prevention of Significant Deterioration of Air Quality (PSD) for each of these pollutants. As such, each new or modified unit addressed in this permit will be subject to PSD review for each PSD pollutant emitted.

It should be noted that ADM is also currently in the process of permitting a new dry mill ethanol plant at this facility. While this project is not addressed under this permit, all applicable requirements apply to this project that would have applied had the two projects been considered one project for permitting purposes (this project alone is major for all PSD pollutants, and the modeling demonstration was performed using refined modeling for each pollutant).

Therefore, the following new or modified emission units covered by this permit are subject to PSD review:

- modification of the existing Gluten Flash Dryer #2 to increase capacity to 65 MMBtu/hr;
- modification of the existing Fluidized Bed Germ Dryer to increase capacity to 55 MMBtu/hr;
- modification of the fermentation process to increase capacity;
- one (1) new rail ethanol loadout station controlled by the existing loadout flare;
- one (1) new 105,000 gallon denaturant storage tank;
- two (2) new 768 MMBtu/hr solid fuel-fired steam generating units along with associated support and control equipment (coal, fly ash, and lime handling equipment and new cooling towers);
- one (1) new 250 MMBtu/hr natural gas-fired steam generating unit (Unit #5);
- modification of the flowrate to the existing cooling towers; and
- new components in VOC service (equipment leaks).

ADM has also recently identified that higher H<sub>2</sub>S levels occur in the biogas stream from the wastewater treatment plant than previously thought. The biogas is currently either flared, or burned in Gluten Flash Dryer #1 in lieu of natural gas. In both cases, the sulfur is oxidized to SO<sub>2</sub>. Therefore, ADM has considered this source as part of this permit application and has included SO<sub>2</sub> emissions from the biogas flare and Gluten Flash Dryer #1 in the modeling demonstration, and has also performed a PSD-BACT analysis for SO<sub>2</sub> from biogas combustion.

In addition the new and modified units listed above, ADM has requested relaxation of existing permit limits, which were taken to make previous modifications minor for PSD review. As a result of relaxation of those limits, these units/processes are also now subject to PSD review. These are discussed below.

*Existing Gas Boilers 1-4* - Existing boilers 1 through 4 were subject to PSD review as part of the 1995 permitting action, at which time each boiler was subject to a NO<sub>x</sub> limit in terms of (lb/MMBtu). Currently, these boilers are operating under a 174.16 ton per year NO<sub>x</sub> limit, which was taken to ensure the expansion of the capacity of the plant from 80,000,000 gallons per year to 100,000,000 per year was not subject to PSD review (the 174.16 ton per year limit was implemented to limit future potential emissions minus past actual emissions to less than 40 tons per year). ADM has requested this limit be removed, and the original PSD-BACT NO<sub>x</sub> limits for these units be reinstated as show in Table 5.

**Table 5. Boiler 1 – 4 NO<sub>x</sub> Limits**

<b>Boiler ID</b>	<b>NO<sub>x</sub> Limit (lb/MMBtu)</b>
Boiler #1	0.2 <sup>a</sup>
Boiler #2	0.074
Boiler #3 & #4	0.074

<sup>a</sup> This permit requires ADM to install a low-NO<sub>x</sub> burner in this boiler pursuant to the Consent Decree requirements. Thus, the limit above is only applicable until the completion of the burner retrofit or permanent boiler shutdown.

*Grain Haul Trucks* - The number of trucks currently permitted to unload grain at this facility is 300 trucks per day (an additional 45 trucks per day are allowed to stage on ADM property but not unload). This limit was taken in 1995 to ensure that the PM<sub>10</sub> increment would not be exceeded due to fugitive dust from the trucking operations. As this limit was not taken as part of a PSD major modification (or PSD avoidance), only the NAAQS compliance and increment preservation must be demonstrated in order to modify or remove this limit. ADM is requesting removal of this limit, and has demonstrated that compliance with the PM<sub>10</sub> increment and NAAQS limits will be met through the use of modified stack heights and pollution controls as addressed in this permit.

*Starch Dryer Project* - ADM is currently limited to a daily corn grind rate of 219,125 bushels per day, and a daily grain receiving rate of 240,000 bushels per day. These limits were taken as part of the permit issued in 1999, which allowed construction of additional starch processing equipment (steam-heated Starch Dryer #2, Starch Bins 13 and 14, a pneumatic starch dryer transport/loadout receiver, and an off-spec starch receiver). Also as part of the 1999 project, the facility accepted a limit on simultaneous filling of Starch Bins 13 and 14. These limits are being removed as part of this permit. As these previous limits were taken to make the Starch Dryer Project minor for PSD review, relaxation of these limits requires the modified units to undergo PSD review for PM and PM<sub>10</sub> at this time. Therefore, this permit provides PM and PM<sub>10</sub> PSD-BACT review and increment and NAAQS compliance demonstration for the modified units.

PSD regulations require that all new or modified major stationary sources submit a PSD-BACT analysis and ambient air quality analysis for all criteria and other pollutants emitted over the significant emission increase thresholds listed in 40 CFR 52.21(b)(23). An ‘Additional Impact Analysis’ must also be conducted as required in 40 CFR 52.21(o).

#### PSD Best Available Control Technology (BACT)

Pursuant to 40 CFR 52.21(j)(3), a major modification shall apply BACT for each regulated NSR pollutant for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emission unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit. BACT is defined as an emission limitation established based on the maximum degree of pollutant reduction, determined on a case-by-case basis, considering technical, economic, energy, and environmental factors. However, BACT cannot be less stringent than emission limits established by an applicable NSPS.

The first step in a BACT analysis is to determine, for the pollutant in question, the most stringent control technology and emission limit available for a similar source or source category. These technologies represent the top control alternative under the BACT analysis. If it can be shown that this level of control is infeasible on the basis of technical, economic, energy, and environmental impacts for the source in question, then the next most stringent level of control is identified and similarly evaluated. This process

continues until the BACT level under consideration cannot be eliminated by any technical, economic, energy or environmental consideration. A “Top-Down” BACT analysis basically consists of the following steps:

- **Identify All Control Technologies.** All control technologies for similar processes, as well as Lowest Achievable Emission Rate (LAER) technologies are included.
- **Eliminate Technically Infeasible Options.** Technologies demonstrated to be infeasible based on physical, chemical, and engineering principles are excluded from further consideration.
- **Rank Technologies By Control Effectiveness.** Technically feasible control technologies are ranked in the order of highest expected emission reduction to lowest expected emission reduction. The ranking also includes expected emission rate, control effectiveness, energy impacts, environmental impacts (including toxic and hazardous air emissions), and economic impacts.
- **Control Technology Evaluation.** The technology ranking is evaluated and case-by-case consideration is given to energy, environmental, and economic impacts. The most effective option not rejected is chosen as BACT and is used to express an enforceable emission limitation for the affected emission unit.

Appendices B (Ethanol Plant Expansion), C (Starch Dryer #2), D (CFB Boilers and Support Facilities), and E (Biogas Vent) of this Fact Sheet contains copies of the BACT analysis performed for this project as submitted by ADM. With the exception of the BACT determination for SO<sub>2</sub> for the CFB boilers, the Department agrees with ADM’s analysis. However, ADM’s SO<sub>2</sub> BACT analysis for the CFB boilers addressed the cost effectiveness of controlling high sulfur fuels (high-sulfur coal) only, and did not address the cost effectiveness of controlling lower sulfur fuels (TDF and low-sulfur coal). As ADM has proposed to burn several types of fuels (with varying sulfur contents) in the CFB boilers, the Department has determined BACT to be a sliding scale limit reflecting a higher level of control for higher sulfur fuels. The final SO<sub>2</sub> limit will vary between 0.11 and 0.20 lb/MMBtu, and is calculated as a 30-day rolling average limit based on the daily fuel sulfur analysis. In addition, the BACT limit for PM/PM<sub>10</sub> emissions from the coal boilers is based on the ability of the top technology (fabric filters) to control filterable PM emissions (EPA Method 5 test). Available control technologies, including fabric filters, are unable to effectively control condensable particulate emissions, therefore a “total” PM BACT limit is not established.

A summary of the BACT requirements for the units subject to PSD review is presented in Table 6.

**Table 6. Proposed PSD-BACT Limits**

<b>Emission Unit</b>				
<b>ID</b>	<b>Emission Unit</b>	<b>Pollutant</b>	<b>Emission Limit</b>	<b>Control Type</b>
EU5-8	Fluidized Bed Germ Dryer	PM	3.0 lb/hr	Cyclone/Wet Scrubber
		PM <sub>10</sub>	3.0 lb/hr	Cyclone/Wet Scrubber
		NO <sub>x</sub>	0.06 lb/MMBtu	Low-NO <sub>x</sub> burner
		SO <sub>2</sub>	0.51 lb/hr	Wet Scrubber
		CO	4.02 lb/hr	Good Combustion Practices
		VOC	1.5 lb/hr	Wet Scrubber
EU6-18	Gluten Flash Dryer #2	PM	9.85 lb/hr	Cyclone/Wet Scrubber
		PM <sub>10</sub>	4.5 lb/hr	Cyclone/Wet Scrubber
		NO <sub>x</sub>	0.06 lb/MMBtu	Low-NO <sub>x</sub> burner
		SO <sub>2</sub>	2.4 lb/hr	Wet Scrubber
		CO	4.74 lb/hr	Good Combustion Practices
		VOC	22.2 lb/hr	Wet Scrubber

<b>Emission Unit ID</b>	<b>Emission Unit</b>	<b>Pollutant</b>	<b>Emission Limit</b>	<b>Control Type</b>
EU4-22	Starch Storage Bin #9 (Off-Spec Starch)	PM/ PM <sub>10</sub>	0.03 lb/hr	Fabric Filters
EU7-32, EU7-33, EU7-34	Fermentation, Distillation	VOC	13.5 lb/hr	CO <sub>2</sub> Scrubber
		SO <sub>2</sub>	2.5 lb/hr	CO <sub>2</sub> Scrubber
EU10-41	Anaerobic Digester Biogas Vent	SO <sub>2</sub>	Gluten Flash Dryer #1 limit of 6.6 lb/hr, and hourly limit on biogas flaring	Wet Scrubber
EU4-45	Starch Dryer #2	PM/ PM <sub>10</sub>	3.03 lb/hr	Cyclone/Wet Scrubber
EU4-46	Starch Storage Bin #13	PM/ PM <sub>10</sub>	0.062 lb/hr	Fabric Filters
EU4-47	Starch Storage Bin #14	PM/ PM <sub>10</sub>	0.062 lb/hr	Fabric Filters
EU4-48	Starch Dryer Loadout	PM/ PM <sub>10</sub>	0.12 lb/hr	Fabric Filters
EU7-90	Liquid Product Loadout (Rail)	VOC	none	Flare
EU9-98	New Natural Gas Boiler #5	PM	1.86 lb/hr	Natural Gas Only
		PM <sub>10</sub>	1.86 lb/hr	Natural Gas Only
		NO <sub>x</sub>	0.036 lb/MMBtu	Low-NO <sub>x</sub> burner
		SO <sub>2</sub>	0.15 lb/hr	Natural Gas Only
		CO	23.6 lb/hr	Good Combustion Practices
		VOC	1.4 lb/hr	Good Combustion Practices
		H <sub>2</sub> SO <sub>4</sub> (mist)	NA	Natural Gas Only
EU9-1A, EU9-1B	New CFB boilers	PM (filterable only)	0.015 lb/MMBtu	Fabric Filter
		PM <sub>10</sub> <sup>1</sup> (filterable and condensable)	0.025 lb/MMBtu	Fabric Filter
		NO <sub>x</sub>	0.07 lb/MMBtu	CFB Technology and SNCR, NH <sub>3</sub> injection limited to a maximum of 10ppm
		SO <sub>2</sub>	0.11 – 0.20 lb/MMBtu	Limestone Injection and Fabric Filter
		CO	0.1 lb/MMBtu	Good Combustion Practices
		VOC	0.007 lb/MMBtu	Good Combustion Practices
		Fluorides (F)	0.0012 lb/MMBtu	Limestone Injection and Fabric Filter
	Coal, ash, lime handling	H <sub>2</sub> SO <sub>4</sub> (mist)	0.01 lb/MMBtu	Limestone Injection and Fabric Filter
		Lead (Pb)	0.0002 lb/MMBtu	Fabric Filter
		PM/ PM <sub>10</sub>	95% control, 0.005 gr/dscf	Fabric Filters



<b>Emission Unit</b>				
<b>ID</b>	<b>Emission Unit</b>	<b>Pollutant</b>	<b>Emission Limit</b>	<b>Control Type</b>
EU7-TK08	Cooling towers	PM/ PM <sub>10</sub>	0.008% drift	Drift Eliminators
	Equipment Leaks	VOC	none	LDAR (Subpart VV)
	New Denaturant Tank	VOC	none	Internal Floating Roof (Subpart Kb)

<sup>1</sup> PM<sub>10</sub> limit for boilers is not based on BACT review. This limit was used for compliance with NAAQS and increment modeling. The use of a fabric filter with a PM (filterable) limit of 0.015 lb/MMBtu is considered BACT.

### PSD Air Quality Impact Analysis

The air quality impact analysis for this modification consists of two components. The first component of the air quality analysis is a preliminary modeling analysis of all new or modified emission sources at the facility (CFB boilers, cooling tower, fluid bed germ dryer, gluten flash dryer, cogen plant stack, rotary car dumping building, coal storage dome, crusher tower, powerhouse silo bay, fly ash transfer/storage, bottom ash collection/transfer/storage, limestone transfer/storage, coal unloading fugitives), to determine if the emissions from the new sources would cause ambient pollutant concentrations in excess of 1) concentration thresholds above which preconstruction ambient air quality monitoring may be required, or 2) SILs, which determine if further modeling is required on a pollutant-by-pollutant basis. The first component analysis was completed for CO, NO<sub>2</sub>, PM<sub>10</sub>, and SO<sub>2</sub>. The Department used the Dry Mill application from ADM for this modeling analysis, which includes all emission points from the Coal Boiler project and the Dry Mill project, thus making the modeling review the most conservative.

The second component of the analysis consists of a refined modeling analysis to demonstrate that the proposed project will not cause or contribute to any violations of applicable AAQS or PSD Increments for those pollutants with concentrations above the respective SILs. This analysis includes sources, which contribute to baseline concentrations of each pollutant, and sources that have been determined to consume available increment for each pollutant. The second component analysis, including all appropriate regional emission sources (other nearby facilities), was completed for annual, 3-hour, and 24-hour SO<sub>2</sub>; annual and 24-hour PM<sub>10</sub>; 1-hour and 8-hour CO; and annual NO<sub>x</sub>.

### Source Input Data

The stack parameters and emission rates for the emission points modeled can be found in the PSD application and in supplemental information received by the Department in 2005/2006. PSD increment-consuming sources, major or minor, within 50 km of the proposed facility were included in the SO<sub>2</sub>, PM<sub>10</sub>, and NO<sub>x</sub> refined analyses.

### Preliminary Analysis for Significant Impacts

The purpose of the preliminary dispersion modeling analysis was to determine if emissions from this modification would cause ambient pollutant concentrations in excess of concentration thresholds above which pre-application ambient air quality monitoring may be required. In addition, the results were reviewed to determine if a SIL would be exceeded for any pollutant. The latest version of the EPA Industrial Source Complex Short-Term dispersion model (ISCST3, Version 5.1.0) was used for this analysis.

The meteorological data used for this analysis consisted of five years (2000-2004) of National Weather Service surface data from the Hastings Municipal Airport in Hastings (station number 94949) and mixing height data for Omaha (station number 94980).

Table 7 shows the results of the pre-application ambient monitoring threshold analysis.

**Table 7. Maximum Modeled ADM CFB Boiler Project Concentrations: Pre-application Monitoring Thresholds**

Pollutant	Averaging Period	Modeled Concentration ( $\mu\text{g}/\text{m}^3$ )	Pre-application Monitoring Threshold Concentration ( $\mu\text{g}/\text{m}^3$ )
CO	1-hr	--	--
	8-hr	25.7	575
SO <sub>2</sub>	Annual	--	--
	24-hr	5.3	13
	3-hr	--	--
PM <sub>10</sub>	Annual	--	--
	24-hr	7.8	10
NO <sub>2</sub>	Annual	0.5	14

The modeling impacts for the proposed modifications fall below the *Pre-application Ambient Monitoring Thresholds* for all the pollutants. This means that the source will not be required to conduct ambient air monitoring prior to submitting their PSD application in accordance with 40 CFR 52.21(m).

#### Refined Modeling Analysis for NAAQS and PSD Increment Compliance

The purpose of the final refined modeling analysis was to demonstrate that the proposed modifications will not cause or contribute to violations of applicable NAAQS or PSD Increments for SO<sub>2</sub> (annual, 3-hour, & 24-hour), PM<sub>10</sub> (annual & 24-hour), CO (1-hour and 8-hour), and NO<sub>x</sub> (annual). The AAQS and PSD increments are shown in Table 8. The Nebraska and National AAQS and PSD increments are identical.

**Table 8. Nebraska and National Ambient Air Quality Standards and PSD Increments**

Pollutant	Averaging Period	Ambient Air Quality Standards		PSD Class II Increments <sup>a</sup>	
		National	Nebraska	National	Nebraska
SO <sub>2</sub>	3-hour <sup>b</sup>	1,300	1,300	512	512
	24-hour <sup>b</sup>	365	365	91	91
	annual	80	80	20	20
PM <sub>10</sub>	24-hour <sup>b</sup>	150	150	30	30
	annual	50	50	17	17
CO	1-hour <sup>b</sup>	40,000	40,000	--	--
	8-hour <sup>b</sup>	10,000	10,000	--	--
NO <sub>x</sub>	annual	100	100	25	25

<sup>a</sup> All standards and increments are in units of  $\mu\text{g}/\text{m}^3$ .

<sup>b</sup> Concentrations or increment is allowed to be exceeded once per year at a single receptor. A second exceedance of the standard or increment constitutes a violation of the standard.

This ambient air quality impact analysis takes into account the combined impacts of emissions from the existing and proposed ADM sources, contributions from nearby major and minor sources, and background concentrations due to distant major and minor sources and natural sources. Based on the potential emissions from ADM and other sources' allowable and actual emissions, this analysis demonstrates facility compliance with AAQS and PSD Increments for SO<sub>2</sub>, PM<sub>10</sub>, CO, and NO<sub>x</sub>.

## Criteria Pollutant Results

The SO<sub>2</sub>, PM<sub>10</sub>, CO, and NO<sub>x</sub> results for PSD Class II Increment consumption and NAAQS compliance demonstration are described below.

### PSD Increment

Results of the criteria pollutant's PSD increment consumption analysis are summarized in Table 9.

**Table 9. Maximum Predicted Increment Consumption**

Averaging Period	Year	UTM Coordinates (m)		H2H Increment Consumption <sup>a</sup> (ug/m <sup>3</sup> )	Allowable PSD Increment (ug/m <sup>3</sup> )
		X	Y		
SO <sub>2</sub> 3-hour <sup>a</sup>	2000	643525.00	4586475.00	189.8	512
	2001	643525.00	4586325.00	181.3	
	2002	643478.62	4586505.00	179.7	
	2003	643476.50	4586405.50	203.6	
	2004	643480.62	4586605.50	201.5	
SO <sub>2</sub> 24-hour <sup>a</sup>	2000	643477.62	4586455.50	73.6	91
	2001	643476.50	4586405.50	75.9	
	2002	643575.00	4586425.00	66.1	
	2003	643476.50	4586405.00	85.3	
	2004	643525.00	4586575.00	82.7	
SO <sub>2</sub> Annual	2000	642988.88	4587031.50	9.8	20
	2001	642988.88	4587031.50	9.9	
	2002	642988.88	4587031.50	9.2	
	2003	642888.88	4587031.50	9.9	
	2004	642888.88	4587031.50	10.5	
PM <sub>10</sub> 24-hour <sup>a</sup>	2000	642475.00	4587175.00	28.4	30
	2001	642638.88	4587031.50	24.0	
	2002	642625.00	4587075.00	23.2	
	2003	642638.88	4587031.50	27.2	
	2004	642538.88	4587031.50	25.7	
PM <sub>10</sub> Annual	2000	642688.88	4587031.50	5.2	17
	2001	642888.88	4587031.50	4.9	
	2002	643038.88	4587031.00	4.7	
	2003	642838.88	4587031.50	5.2	
	2004	642788.88	4587031.50	5.4	
NO <sub>x</sub> Annual	2000	637825.00	4588225.00	11.2	25
	2001	637825.00	4588225.00	12.2	
	2002	637825.00	4588225.00	12.2	
	2003	637825.00	4588225.00	11.3	
	2004	637700.00	4588300.00	20.2	

<sup>a</sup> Values shown are the highest-second-high (H2H) concentrations, since one exceedance of the short-term standard is allowed per year.

### Ambient Air Quality

The results for AAQS compliance are shown in Table 10 for the criteria pollutants' concentrations, including contributions from existing sources criteria pollutants emissions in the project area. As shown in Table 10, the concentrations are predicted to be below the ambient standards except for PM<sub>10</sub>.

**Table 10. Maximum Predicted Ambient Concentrations**

Averaging Period	Year	UTM Coordinates (m)		Background (µg/m <sup>3</sup> )	Modeled (µg/m <sup>3</sup> )	Total (µg/m <sup>3</sup> )	AAQS (µg/m <sup>3</sup> )
		X	Y				
SO <sub>2</sub> 3-hour <sup>a</sup>	2000	643675.00	4588525.00	120	664.4	784.4	1,300
	2001	643775.00	4588325.00		713.7	833.7	
	2002	643875.00	4588525.00		637.0	757.0	
	2003	643675.00	4588525.00		652.0	772.0	
	2004	643575.00	4588525.00		664.4	784.4	
SO <sub>2</sub> 24-hour <sup>a</sup>	2000	643675.00	4588625.00	48	232.3	280.3	365
	2001	643975.00	4588225.00		261.5	309.5	
	2002	643875.00	4588625.00		282.1	330.1	
	2003	643675.00	4588625.00		278.5	326.5	
	2004	643575.00	4588625.00		264.0	312.0	
SO <sub>2</sub> Annual	2000	643875.00	4588225.00	12	30.7	42.7	80
	2001	643875.00	4888625.00		32.4	44.4	
	2002	643875.00	4888625.00		36.5	48.5	
	2003	643775.00	4888625.00		29.8	41.8	
	2004	643775.00	4888625.00		31.1	43.1	
PM <sub>10</sub> 24-hour <sup>b</sup>	2000 – 2004	635075.00	4588725.00	60	438.2	<b>498.2</b>	150
PM <sub>10</sub> Annual	2000	635075.00	4588725.00	25	80.8	<b>105.8</b>	50
	2001	635075.00	4588725.00		94.6	<b>119.6</b>	
	2002	635075.00	4588725.00		89.8	<b>114.8</b>	
	2003	635075.00	4588725.00		84.8	<b>109.8</b>	
	2004	635075.00	4588725.00		87.6	<b>112.6</b>	
NO <sub>x</sub> Annual	2000	637825.00	4588225.00	15	11.2	26.2	100
	2001	637825.00	4588225.00		12.2	27.2	
	2002	637825.00	4588225.00		12.2	27.2	
	2003	637825.00	4588225.00		11.3	26.3	
	2004	637825.00	4588225.00		11.5	26.5	
CO 1-hour <sup>a</sup>	2000	643088.88	4587030.00	7570	168.6	7738.6	40,000
	2001	643075.00	4587075.00		163.3	7733.3	
	2002	643138.88	4587029.50		168.2	7738.2	
	2003	643338.88	4587027.00		163.3	7733.3	
	2004	642938.88	4587031.50		167.1	7737.1	
CO 8-hour <sup>a</sup>	2000	642625.00	4587075.00	2330	60.9	2390.9	10,000
	2001	643275.00	4587075.00		67.2	2397.2	
	2002	642475.00	4587175.00		57.9	2387.9	
	2003	643088.88	4587030.00		67.3	2397.2	
	2004	643477.62	4586455.50		57.6	2387.6	

<sup>a</sup> The values shown are the highest-second-high (H2H) results, since one exceedance of the short term standard is allowed per year at each location.

<sup>b</sup> PM<sub>10</sub> 24-hour concentrations are based on a combined 5-year file that is run instead of running each year individually. Concentrations are based on High 6<sup>th</sup> High, since one exceedance is allowed per year.

#### *Significance*

A receptor analysis was completed for PM<sub>10</sub> annual and 24-hour concentrations since with nearby sources included in the model, PM<sub>10</sub> is out of compliance for the AAQS.

For PM<sub>10</sub> annual, at any receptor that was over the AAQS limit of 50 ug/m<sup>3</sup> (background included), the ADM concentrations at that receptor would need to stay below 1 ug/m<sup>3</sup>. Each receptor was evaluated for all five years, and ADM is shown to be insignificant.

For PM<sub>10</sub> 24-hour, at any receptor that was over the AAQS limit of 150 ug/m<sup>3</sup> (background included), the ADM concentrations at that receptor would need to stay below 5 ug/m<sup>3</sup>. Each receptor was evaluated for all five years, and ADM is shown to be insignificant.

### Air Quality Impact Summary

The analyses described above demonstrate that the proposed modification will comply with all applicable AAQS and PSD increments.

### Additional Impacts Analysis

An Additional Impacts Analysis, as required by 40 CFR 52.21(o), describes air quality and related impacts due to associated growth and construction, as well as potential impacts of atmospheric emissions on soils, vegetation, and visibility impairment. This analysis indicates no adverse impacts. This information is summarized as follows:

#### *Visibility Impacts*

A plume visibility screen modeling analysis was performed for the proposed modification. Because the nearest Federal Class I areas are several hundred kilometers away from the proposed facility site, the potential impacts at the following Class II areas were evaluated: Fremont Lakes State Recreation Area (65 km east of Columbus), Pawnee Lake State Recreation Area (78 km southeast of Columbus), Branched Oak State Recreation Area (65 km southeast of Columbus), North Loup State Recreation Area (92 km west of Columbus), Willow Creek State Recreation Area (79 km north of Columbus), Dead Timber State Recreation Area (65 km northeast of Columbus), Pioneer State Recreation Area (74 km southeast of Columbus), and Two Rivers State Recreation Area (85 km southeast of Columbus).

The results of the Level 1 screening analysis indicated that emissions from the proposed modification would not result in exceedances of the visibility screening criteria inside the identified Class II areas. Therefore, the proposed modification should not decrease the visibility at the nearby Class II areas or any Federal Class I area.

As documented in the PSD Application, impacts of the proposed modification on soils, vegetation, and visibility from atmospheric emissions are expected to be negligible.

### Air Quality Monitoring

Pre-application monitoring is required under the PSD regulations in 40 CFR 52.21(m)(1) for those modifications at a source that are anticipated to produce ambient concentrations equal to or greater than thresholds indicated in 40 CFR 52.21(i)(8)(i). ADM's preliminary dispersion modeling analysis predicted that the potential ambient impacts would not exceed the monitoring thresholds. As a result pre-application monitoring is not required.

### **Title 129, Chapter 20, Section 001 - Process Weight Rate**

Each of the permitted emission rate limitations ensures the process weight rate limitations will not be exceeded. The following formulas were used to determine compliance:

for process weight rates up to 60,000 lbs/hr,  $E = 4.10 p^{0.67}$ , and

for process weight rates in excess of 60,000 lbs/hr,  $E = 55.0 p^{0.11} - 40$

where  $E$  = rate of emissions in lbs/hr and  
 $p$  = process weight rate in tons/hr.

The facility is in compliance with the process weight rate limitations as illustrated in Appendix A (Emissions Calculations).

#### **Title 129, Chapter 20, Section 002 -Particulate Emissions from Combustion Sources**

This facility is in compliance with this regulation because the fuels combusted at this facility are coal, TDF, natural gas, diesel fuel, and methane, and a baghouse will be installed on the new CFB boilers. The allowable emission rates per Title 129, Chapter 20 Section 002 are shown in Appendix A of this fact sheet.

#### **Title 129, Chapter 20, Section 004 - Opacity**

This rule limits opacity from all equipment at the facility. It is very unlikely the fuel burning equipment would exceed this standard due to the particulate controls on the coal-fired boilers, and all other units burn natural gas, methane, or diesel fuel only. In addition, the equipment controlled by baghouses, scrubbers, and cyclones should be able to meet this standard and no exceedances of this standard have been experienced by this source in the past.

#### **Title 129, Chapter 24 - Sulfur Compounds Emissions**

This facility is in compliance with this regulation because the fuels combusted at this facility are coal, TDF, natural gas, diesel fuel, and methane. The regulation limits sulfur compound emissions from fossil fuel burning to less than 2.5 lbs/MMBtu. The limited emission rates for fuel combustion sources at this facility are shown in Appendix A of this fact sheet.

#### **Title 129, Chapter 27, Section 002 - Best Available Control Technology**

This facility is subject to HAP-BACT since potential individual HAP emissions exceed 2.5 tons/year and combined HAP emissions exceed 10 tons/year. Table 11 shows the HAP-BACT equipment and activities required by the permit pursuant to Title 129, Chapter 27, Section 002.

**Table 11. HAP BACT Requirements**

<b>Emission Unit Ids</b>	<b>Emission Unit Description</b>	<b>BACT Equipment/Activities</b>
EU3-5	Millhouse Ventilation System	Scrubber with 95% VOC control
EU5-7A, EU5-7B, EU5-7C	Germ Dryers #1-3	Scrubber with 95% VOC control
EU5-8	Fluidized Bed Germ Dryer	New Scrubber (VOC limit)
EU5-9A, EU5-9B, EU5-9C, EU5-12	Germ Cooling	No control
EU6-17, EU6-19, EU6-44	Gluten Cooling and Recycle	No control
EU6-16, EU6-18	Gluten Flash Dryer #1 and #2	Existing Scrubbers (VOC limit)
EU7-32, EU7-33, EU7-34	Fermentation/Distillation	Scrubber with either a 65% combined HAP control, or a maximum HAP exhaust concentration of 20 ppmvd
EU8-35, EU8-36	Carbon Furnace #1 and #2	Good Air Pollution Control Practice (VOC limit)
EU9-38 EU9-39, EU9-40, EU9-41, EU9-98	Boilers #1-5	Natural Gas only, compliance with the boiler NESHAP (40 CFR Part 63, Subpart DDDDD)
EU10-41	Anaerobic Digester Biogas	Flare
EU11-43	Fiber Dewatering	No add-on control (VOC limit)
EU6-66, EU6-67, EU6-68	Gluten RVFs	Scrubber with 95% VOC control (will be routed to Millhouse Scrubber)
EU12-69, EU12-70	Stillage/Steepwater evaporators	Scrubber with 95% VOC control (will be routed to Millhouse Scrubber)
EU7-90	Liquid Product Loadout	Submerged filling, vapor recovery system and flare
EU8-91	HCl Storage Tank	Acid Gas Scrubber
EU-95, EU-96, EU-97, EU-99, EU-107, EU-108	Diesel Generators & Fire Pumps	Good Combustion Practices, 400 hour/yr limit
EU9-1A, EU9-1B	CFB Boilers	Compliance with the boiler NESHAP (40 CFR Part 63, Subpart DDDDD), fabric filters
EQ_LKS_FUG	Equipment Leaks	LDAR program
EU7-TK01, EU7-TK02, EU7-TK03, EU7-TK04, EU7-TK05, EU7-TK06, EU7-TK08	Ethanol and Denaturant Storage Tanks	Internal floating roof
EU7-TK07	Corrosion Inhibitor Storage Tank	No control
WETFEED_FUG	Wet Feed Pile	No control

With the exception of the new coal-fired boilers and the HCl storage tank scrubber, the BACT analysis for HAPs is identical to the PSD-BACT for VOC emissions and the Consent-decree required VOC controls, since the majority of the HAPs emitted at this source are VOC-HAPs. As required by the PSD-BACT determinations and Consent Decree requirements, the VOC emission limits identified in the table above will effectively limit HAP emissions from these sources.

HAP emissions from the coal-fired boilers are also controlled by the PSD-related PM and VOC BACT conclusions as discussed in the PSD discussion. Controlled HAP emissions from the HCl scrubber are estimated to be 1.26 pounds per year, which makes additional control not cost effective, therefore, HAP-BACT for this operation is the continued use of the acid gas scrubber (SV-91). Finally, due to the fugitive nature and minimal emissions generated from the wet feed pile (the feed contains approximately 60% water by weight and is stored outside on an open pad), there are no cost-effective HAP control options for the wet feed operations.

Appendix F of this Fact Sheet contains copies of the HAP-BACT analysis performed for existing sources at this facility as submitted by the applicant and approved by The Department.

### **Title 129, Chapter 27, Section 003 -Maximum Achievable Control Technology**

This facility will be considered a major source of HAP after issuance of this permit. Existing sources of HAP at this facility are not subject to the case-by-case MACT requirements (Section 112(g) of the Clean Air Act), as they were constructed prior to promulgation of the case-by-case MACT rule in 40 CFR, Part 63 sections 63.40 through 63.44.

Both of the proposed coal-fired boilers have the potential to emit greater than 10 tons per year of any single HAP and greater than 25 tons per year of total HAP. Therefore, these units are subject to Title 129, Chapter 27 (Hazardous Air Pollutants; Maximum Achievable Control Technology). As discussed below, these boilers are subject to the requirements of 40 CFR, Part 63 Subpart DDDDD (Industrial, Commercial and Institutional Boilers and Process Heaters). In addition, the existing and new natural gas boilers #1 thru #5 are also subject to the requirements of 40 CFR, Part 63 Subpart DDDDD (Industrial, Commercial and Institutional Boilers and Process Heaters), and the ethanol plant sources (including all storage tanks, transfer stations, pumps, compressors, agitators, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, and instrumentation systems) are subject to the requirements of 40 CFR, Part 63 Subpart FFFF (National Emission Standards for Hazardous Air Pollutants for Miscellaneous Organic Chemical Manufacturing).

### **Title 129, Chapter 28 -National Emission Standards for Hazardous Air Pollutants (NESHAP, 40 CFR 63)**

Subpart F – National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry: This subpart, adopted by reference in Title 129, Chapter 28, Section 001.20, applies to manufacturing facilities which produce a chemical on the list of primary products listed in the rule {§63.100(b)(1)}, and use an organic HAP as a reactant or manufacture the chemical as a product or co-product {§63.100(b)(2)}, and are located at a plant site that is a major source ( $\geq 10$  tons/year of individual HAP or  $\geq 25$  tons/year of combined HAPs). This plant produces ethanol, which contains acetaldehyde and methanol, as well as the HAPs in the denaturant. This facility is not subject to this subpart because the primary product is ethanol (which is not on the primary product list in this subpart).

Subpart G – National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and



Wastewater: This subpart, adopted by reference in Title 129, Chapter 28, Section 001.21, applies to the same manufacturing facilities as Subpart F, but only for all of the process vents, storage vessels, transfer racks and wastewater streams. Since this plant is exempt from Subpart F, it is also exempt from Subpart G.

Subpart H – National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry for Equipment Leaks: This subpart, adopted by reference in Title 129, Chapter 28, Section 001.22, applies to the same manufacturing facilities as Subpart F, but only for the following equipment: pumps, compressors, agitators, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, instrumentation systems, and control devices or closed vent systems that are intended in operate in organic hazardous air pollutant service 300 hours or more during the calendar year. Since this plant is exempt from Subpart F, it is also exempt from Subpart H.

Subpart Q – National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers: This subpart, adopted by reference in Title 129, Chapter 28, Section 001.04, applies to industrial process cooling towers that are operated with chromium-based water treatment chemicals and are located at major facilities for HAPs ( $\geq 10$  tons/year of individual HAP or  $\geq 25$  tons/year of combined HAPs). This facility is exempt from this subpart because no chromium-based water treatment chemicals are used in the cooling towers.

Subpart EEEE – National Emission Standards for Hazardous Air Pollutants for Organic Liquids Distribution (non-gasoline): This subpart was promulgated February 3, 2004 (69 FR 5063, Federal Register, Vol. 69, No. 22, pages 5038 to 5086). This subpart, adopted by reference in Title 129, Chapter 28, Section 001.83, applies to major HAP facilities ( $\geq 10$  tons/year of individual HAP or  $\geq 25$  tons/year of combined HAPs), which have organic liquids distribution. Organic liquids are all crude oils other than black oil, and those liquids or liquid mixtures, except gasoline, that contain a total of 5 percent by weight or more of the organic HAP listed in the subpart (including acetaldehyde, methanol, benzene, carbon disulfide, cumene, ethyl benzene, hexane, toluene, xylenes). Fuels used on-site (such as fuels used for fleet refueling) are exempt from this subpart. This facility is not subject to this subpart because ethanol and denatured ethanol do not contain more than 5 percent by weight organic HAPs.

Subpart FFFF – National Emission Standards for Hazardous Air Pollutants for Miscellaneous Organic Chemical Manufacturing: This subpart was promulgated November 10, 2003 (Federal Register, Vol. 68, No. 217, pages 63852 to 63911). This subpart, adopted by reference in Title 129, Chapter 28, Section 001.78, applies to major HAP facilities ( $\geq 10$  tons/year of individual HAP or  $\geq 25$  tons/year of combined HAPs), which own or operate miscellaneous organic chemical manufacturing process units (MCPU). An MCPU includes equipment necessary to operate a miscellaneous organic chemical manufacturing process, as defined in §63.2550 (process includes reaction, recovery, separation, purification, or other activity, operation, manufacture, or treatment which are used to produce a product of isolated intermediate), that produce an organic chemical(s) in the specified SIC (includes SIC 2869), and it processes, uses, or produces HAP. As a major HAP source, this facility is subject to this rule. New sources are subject to this rule upon startup, and existing sources must comply with this rule by May 10, 2008.

Subpart DDDDD – Industrial, Commercial and Institutional Boilers and Process Heaters: This subpart was promulgated September 13, 2004 (69 FR 55253, Federal Register, Vol. 69, No. 176, pages 55218 to 55286). This subpart, adopted by reference in Title 129, Chapter 28, Section 001.90, applies to boilers and indirect process heaters that are located at major HAP sources ( $\geq 10$  tons/year of individual HAP or  $\geq 25$  tons/year of combined HAPs). The boilers at this facility are subject to this subpart because the facility has HAP emissions greater than 25 tons per year. Boilers #1 thru #4 are considered existing large gaseous fuel units and must be in compliance with this rule by September 13, 2007, the new boiler #5 is

considered a new gaseous fuel unit and must be in compliance with this rule upon startup, and the new CFB boilers are considered new large solid fuel units and must also be in compliance with this rule upon startup. All the boilers are watertube boilers. The existing boilers do not have specific emission limits under the rule, while the new CFB boilers are subject to the emission limitations as shown in Table 12 (new boiler #5 is only subject to the CO limit):

**Table 12. Boiler NESHAP Requirements**

<b>Pollutant</b>	<b>Emission Limits</b>
PM	0.025 lbs/MMBtu
(or Total Selected Metal*)	(or 0.0003 lbs/MMBtu)
CO	400 ppm by volume on a dry basis corrected to 7 percent oxygen based on 30-day rolling average
Hydrochloric acid (HCl)	0.02 lbs/MMBtu
Mercury compounds	0.000003 lbs/MMBtu

\* Total Selected Metal (TSM) is defined as the combination of arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium compounds.

The Starch and Germ Dryers use steam to dry the material, and the Fluidized Bed Germ Dryer and Gluten Flash Dryers directly heat the material. Therefore, none of the Dryers are subject to the NESHAP.

### **Operating parameters of control equipment**

The operating parameters' monitoring requirements for the control equipment are to ensure the equipment is operated in the same condition as during the stack testing. The monitored operating parameters expected for each piece of control equipment are listed in the permit (i.e. pressure differential). The operating parameters are those that the facility normally monitors to ensure the control equipment is operating properly. For example, a scrubber can have the following operating parameters:

- pressure drops (indicator of scrubber bed condition or gas flow rates);
- gas outlet temperatures (indicator of liquid to gas distribution or inadequate liquid flow);
- gas flow rate evaluation by measuring fan motor current (establishes historical operating range);
- liquor inlet pressure (indicator of nozzle corrosion or plugging);
- liquor turbidity and solids settling rate (only if recirculating scrubbant is used);
- liquor pH (establishes historical operating rate); and
- liquor recirculation rate (if applicable).

### **Maintenance of equipment**

The equipment is to be maintained as specified in the manufacturer's documentation or equivalent maintenance procedures developed over time that the facility uses for prevention of poor performance requiring corrective action (atypical operating parameters, leaks, noise, etc). For example, during scrubber shutdowns, the internal conditions (confined entry area) should be checked for things such as:

- Is the demister, packing, or tray orifices relatively free of solids build-up?
- Are the trays in the scrubber sagging?
- Are any of the nozzles plugged?
- Is there excessive corrosion in downcomers, trays or other areas?
- Are there any broken downcomers?

## Stack Testing

This permit contains extensive stack testing and emissions monitoring requirements, for both new and modified units, as well as existing units. In some instances, a single test is required for a group of similar units, unless the single test shows non-compliance with emission limits contained in the permit, in which case all similar units are required to be tested. The permit identifies which specific units are to be tested, and which pollutants are to be monitored using a CEMS. Table 13 below presents a summary of the testing requirements for this facility.

**Table 13. Stack Testing Requirements**

Stack/Vent ID's	Emission Unit Description	Pollutants to be tested
SV-1 and SV-2	Corn Receiving (Truck)	None – tested 1/2003
SV-3	Corn Cleaner Fines	PM/PM <sub>10</sub>
SV-4	Corn Cleaner	None – tested 1/2003
SV-42	Corn Fines Transfer	PM/PM <sub>10</sub> (use EU2-3 test)
SV-54 through SV-61, and SV-72 through SV-89	Truck and Rail Corn Silos	PM/PM <sub>10</sub> (initial testing only required for one Silo)
SV-71	Rail Corn Storage and Handling	None – tested 1/2003
SV-105 and SV-106	Rail Corn Silo	PM/PM <sub>10</sub> (initial testing only required for one Silo)
SV-5	Millhouse/Feedhouse	PM/PM <sub>10</sub> , SO <sub>2</sub> , VOC, HAPs
SV-43	Fiber Dewatering	PM/PM <sub>10</sub> , SO <sub>2</sub> , VOC, HAPs
SV-6	Starch Dryer #1	None – tested 5/2005
SV-7	Germ Dryers #1-3	PM/PM <sub>10</sub> , SO <sub>2</sub> , VOC, HAPs
SV-8	Fluidized Bed Germ Dryer #1	PM/PM <sub>10</sub> , NO <sub>x</sub> , CO, SO <sub>2</sub> , VOC, HAPs
SV-16	Gluten Flash Dryer #1	PM/PM <sub>10</sub> , NO <sub>x</sub> , CO, SO <sub>2</sub> , VOC, HAPs
SV-18	Gluten Flash Dryer #2	PM/PM <sub>10</sub> , NO <sub>x</sub> , CO, SO <sub>2</sub> , VOC, HAPs
SV-45	Starch Dryer #2	None – tested 1/2001
SV-9	Germ Coolers #1-3	PM/PM <sub>10</sub> , VOC, HAPs
SV-12	Germ Cooler #4	PM/PM <sub>10</sub> , VOC, HAPs (use EU5-9A test)
SV-17, SV-19, SV-44	Gluten Cooler #1 and #2, Gluten recycle	PM/PM <sub>10</sub> , VOC, HAPs (initial testing required for one unit)
SV-20 through SV-31	Starch, Gluten, and Germ Storage Bins	None – tested 1/2001 (use SV-22 test)

**Table 13. Stack Testing Requirements (Continued)**

Stack/Vent ID's	Emission Unit Description	Pollutants to be tested
SV-46, SV-47, SV-48	Starch Bins #13 and #14, Starch Dryer Loadout	None – tested 1/2001

SV-32, SV-33, SV-34	Fermentation/Distillation Scrubber	SO <sub>2</sub> , VOC, HAPs
SV-35 and SV-36	Carbon Furnaces #1 and #2	None – tested between 8/2001 and 5/2002
SV-38, SV-39, SV-40, SV-98	Boilers #1-5	None – AP-42 emission factors used, NO <sub>x</sub> CEMS
SV-62	Lime Silo	PM/PM <sub>10</sub>
SV-63	Soda Ash Receiving	PM/PM <sub>10</sub>
SV-COGEN1	CFB Boilers #1 and #2	PM/PM <sub>10</sub> , NO <sub>x</sub> , CO, SO <sub>2</sub> , VOC, HAPs, F (as HF), H <sub>2</sub> SO <sub>4</sub> , Pb, HCl, Hg, Opacity
SV-COGEN2 through SV-COGEN6	Coal Handling	PM/PM <sub>10</sub> (initial testing only required for one vent), Opacity
SV-COGEN7 through SV-COGEN12	Ash Handling	PM/PM <sub>10</sub> (initial testing only required for one vent)
SV-COGEN13 through SV-COGEN16	Limestone Handling	PM/PM <sub>10</sub> (initial testing only required for one vent)
SV- SETHA 1-6, SV-FRUC 1-3, COGEN17-18, COGEN 19-22	Cooling Towers	TDS (one sample per month per cooling tower)

**Permit conditions specific to the proposed permit are discussed as follows:**

The proper installation and usage of the control equipment (baghouses, scrubbers, limestone injection, vapor recovery system, and flares) and the emission rate (lbs/hr, drift loss percent, ppm of TDS) limitations are required to ensure compliance with the NAAQS and Title 129, Chapter 20. The baghouses, scrubbers, and boilers are required to be stack tested per Title 129, Chapter 34. These stack tests are required to ensure compliance of the emission rate limitations (lbs/hr) and to establish operating parameters for the control devices. All the stack tests for VOC emissions will also include speciation and quantification of hazardous air pollutants, to confirm the HAP composition of the VOC emissions, and percent control efficiency for VOC and HAPs to confirm HAP BACT is appropriate. No new stack testing requirements are in this permit for existing sources that have not been modified and that have been previously tested.

**XIII (A) Requirements for the Grain Handling and Processing Operations**

- (1) The condition requires that emissions from the grain receiving and handling operations to be captured and controlled by baghouses. This condition is to demonstrate compliance with Title 129, Chapters 19 and 20.
- (2) The source shall follow the manufacturer's manual or create their own manual detailing how to properly operate, inspect, and maintain the grain handling and processing equipment. Emission calculations in this permit rely on the use of properly operated and well-maintained grain handling and processing equipment.
- (3) The source shall follow the manufacturer's manual or create their own manual detailing how to properly operate, inspect, and maintain the dry dust collectors (baghouses) and their pressure differential indicators. Emission calculations in this permit rely on the use of properly operated and well-maintained dry dust collectors.
- (4) PM and PM<sub>10</sub> hourly emissions limitations for the grain handling and processing baghouses are to ensure the facility demonstrates compliance with Title 129, Chapters 4, 19 and 20.
- (5) Contains the requirements of 40 CFR, Part 60, Subpart DD (Grain Elevators).

- (6) Requires the facility to conduct a stack test to demonstrate compliance with the hourly limitations in Condition XIII.(A)(4). This permit contains testing requirements for those units for which no previous testing has been performed (either at the same, or a similar unit), and for those units that have been added and/or modified as part of this project. In some cases, only one of a group of similar units is required to be tested, unless that test shows non-compliance with the emission limits, in which case all similar units must be tested.
- (7) Design requirements to control fugitive PM emissions from the railcar unloading stations to ensure compliance with Title 129, Chapters 4 and 19. This condition was carried forward from the July 3, 2001 Construction Permit which approved construction of the rail receiving operations.

#### XIII.(B) Requirements for the Millhouse/Feedhouse Operations

- (1) Requires the millhouse/feedhouse operations be controlled by a wet scrubber system to demonstrate compliance with Title 129, Chapters 4 and 19.
- (2) The source shall follow the manufacturer's manual or create their own manual detailing how to properly operate, inspect, and maintain the scrubber and its operating parameter indicator(s). Emission calculations in this permit rely on the use of properly operated and a well-maintained scrubber.
- (3) PM, PM<sub>10</sub>, and SO<sub>2</sub> hourly emission limitations on the millhouse scrubber are to ensure the facility demonstrates compliance with Title 129, Chapters 4 and 19.
- (4) A 20 ppmvd or 95% VOC control requirement per the Consent Decree.
- (5) Requires the facility to conduct a stack test on the millhouse scrubber system stack to demonstrate compliance with the emission limitations in Conditions XIII.(B)(3) and (B)(4), and to fully characterize HAP emissions from the millhouse/feedhouse operations.

#### XIII.(C) Requirements for Fiber Dewatering.

- (1) PM, PM<sub>10</sub>, SO<sub>2</sub>, and VOC hourly emission limitations on the fiber dewatering operation to ensure the facility demonstrates compliance with Title 129, Chapters 19 and 27.
- (2) Requires the facility to conduct a stack test to demonstrate compliance with the hourly limitations in Condition XIII.(C)(1).
- (3) The source shall follow the manufacturer's manual or create their own manual detailing how to properly operate, inspect, and maintain the fiber dewatering equipment. Emission calculations in this permit rely on the use of properly operated and well-maintained fiber dewatering equipment.

#### XIII.(D) Requirements for Product Drying Operations

- (1) Identifies the drying equipment used at this facility and their associated control equipment to demonstrate compliance with Title 129, Chapters 19 and 27.
- (2) Fuel type limitation for the dryers to demonstrate compliance with Title 129, Chapters 4 and 19.
- (3) The source shall follow the manufacturer's manual or create their own manual detailing how to properly operate, inspect, and maintain the product drying equipment. Emission calculations in this permit rely on the use of properly operated and well-maintained product drying equipment.
- (4) PM, PM<sub>10</sub>, NO<sub>x</sub>, SO<sub>2</sub>, CO, and VOC hourly emission limitations on the drying equipment to ensure the facility demonstrates compliance with Title 129, Chapters 4 and 19. The PM limit for the Gluten Flash Dryer #1 is specifically for filterable PM, as that is how the unit was originally permitted in the July 12, 1995 PSD permit. Subsequent to that permit, ADM conducted testing which indicated higher levels of PM<sub>10</sub> when condensable particulate was considered, therefore, a separate PM<sub>10</sub> limit (which does include

- condensables) has been added to the permit to ensure compliance with the NAAQS and PSD modeling requirements.
- (5) The source shall follow the manufacturer's manual or create their own manual detailing how to properly operate, inspect, and maintain the scrubbers and their operating parameter indicator(s). Emission calculations in this permit rely on the use of properly operated and well-maintained scrubbers. Previously, the frequency of the control device parameter recording was once per shift. This permit revises the frequency to once per day, which the Department feels is a sufficient monitoring frequency to ensure the control device is operating correctly.
  - (6) Requires the facility to conduct stack testing to demonstrate compliance with the hourly limitations in Condition XIII.(D)(4). As testing has already been performed on the Starch Dryers that demonstrate compliance with the emission limits for those units, they are not required to be tested as part of this permit.

#### XIII.(E) Requirements for Product Cooling and Storage

- (1) Identifies the equipment used at this facility in germ, gluten, and starch cooling and storage operations, and associated control devices to demonstrate compliance with Title 129, Chapters 4 and 19.
- (2) The source shall follow the manufacturer's manual or create their own manual detailing how to properly operate, inspect, and maintain the cooling and storage equipment. Emission calculations in this permit rely on the use of properly operated and well-maintained cooling and storage equipment.
- (3) The source shall follow the manufacturer's manual or create their own manual detailing how to properly operate, inspect, and maintain the dry dust collectors (baghouses) and their pressure differential indicators. Emission calculations in this permit rely on the use of properly operated and well-maintained dry dust collectors. Previously, the frequency of the control device parameter recording was once per shift. This permit revises the frequency to once per day, which the Department feels is a sufficient monitoring frequency to ensure the control device is operating correctly.
- (4) VOC, PM, and PM<sub>10</sub> hourly emission limitations on the cooling and storage equipment to ensure the facility demonstrates compliance with Title 129, Chapters 4 and 19.
- (5) Requires the facility to conduct stack testing to demonstrate compliance with the hourly limitations in Condition XIII.(E)(4). This permit contains testing requirements for those units for which no previous testing has been performed (either at the same, or a similar unit), and for those units that have been added and/or modified as part of this project. In some cases, only one of a group of similar units is required to be tested, unless that test shows non-compliance with the emission limits, in which case all similar units must be tested.

#### XIII.(F) Requirements for Fermentation and Distillation

- (1) The condition requires the fermentation and distillation operations to be controlled by a wet scrubber system consisting of three scrubbers. This condition is to demonstrate compliance with Title 129, Chapters 19 and 27.
- (2) The source shall follow the manufacturer's manual or create their own manual detailing how to properly operate, inspect, and maintain the scrubbers and their operating parameter indicator(s). Emission calculations in this permit rely on the use of properly operated and well-maintained scrubbers.
- (3) SO<sub>2</sub> and VOC hourly emission limitations on the scrubbers are to ensure the facility demonstrates compliance with Title 129, Chapters 4, 19, and 27.
- (4) This condition requires that the fermentation/distillation scrubber system meet either a 65% HAP control efficiency, or a maximum total HAP exhaust concentration of less than

or equal to 20 ppmvd. These requirements are needed to meet the requirement of Chapter 27 BACT. A weighted average of the control efficiency for the combined HAPs is used as a HAP-BACT limit because some of the individual HAPs with smaller emission rates (i.e. less than 0.5 tons per year) may be cost prohibitive to achieve 65+% control efficiency.

$$\text{Efficiency} = \left( 1 - \left( \frac{\sum C}{\sum U} \right) \right) * 100$$

Where: Efficiency = the combined HAP control efficiency

C = the controlled (outlet) individual HAP emission rates (lbs/hr)

U = the uncontrolled (inlet) individual HAP emission rates (lbs/hr)

Preliminary testing at another ethanol plant indicates that regular scrubber control of HAP may be much less than expected (acetaldehyde control of ~ 30%), but the injection of sodium bisulfite improved removal of HAP in the scrubber. It should be noted that the lack of existing test data may result in the required control efficiency being adjusted up or down if future test results prove 65% is not HAP-BACT (subject to public comment). This condition also requires the scrubbers meet the control efficiency requirement from the consent decree (95% VOC control) or a maximum VOC concentration of 20 ppmvd.

- (5) Compliance tests requirement for the CO<sub>2</sub> scrubber in accordance with Title 129, Chapter 34 or other NDEQ approved testing method. The control efficiency determination is to demonstrate that the scrubber is the appropriate control device for HAP-BACT compliance for the fermentation operations. The HAP emissions are to be speciated and quantified to determine the actual HAP composition of the emissions from the fermentation operations. The tests will be used to demonstrate compliance with emission limitations in Conditions XIII.(F)(3) and (F)(4).

#### XIII.(G) Requirements for the Storage Tanks

- (1) Identifies the storage tanks located at this facility to demonstrate compliance with Title 129, Chapters 18, 19 and 27.
- (2) NSPS, Subpart Kb requirements for tanks EU-TK05, EU-TK06, and EU-TK08. Each of these tanks will have an internal floating roof, a vapor mounted wiper, and a rim-mounted wiper for emissions control.
- (3) Pursuant to Title 129, Chapter 27, tanks EU-TK01, EU-TK02, EU-TK03, and EU-TK04 are subject to the requirements of Conditions XIII.(G)(2)(a-b).

#### XIII.(H) Requirements for Liquid Product Loading

- (1) Submerged loading required when transferring liquid to limit the amount of VOC and HAPs emitted during the transfer process to demonstrate compliance with Title 129, Chapters 19 and 27.
- (2) The source shall follow the manufacturer's manual or create their own manual detailing how to properly operate, inspect, and maintain the vapor recovery system, flare and flare monitoring device/system. Emission calculations in this permit rely on the use of properly operated and well-maintained closed vapor recovery system (100% capture of vapors) and flare. This condition is to demonstrate compliance with Title 129, Chapter 19 and 27.

#### XIII.(I) Requirements for the Carbon Furnaces

- (1) Fuel type limitation and maintenance requirements for the carbon furnaces to demonstrate compliance with Title 129, Chapters 4, 19, and 27.
- (2) Control device requirements for the carbon furnaces to demonstrate compliance with Title 129, Chapters 4, 19, and 27.
- (3) The source shall follow the manufacturer's manual or create their own manual detailing how to properly operate, inspect, and maintain the scrubbers and their operating parameter indicator(s). Emission calculations in this permit rely on the use of properly operated and well-maintained scrubbers.
- (4) Hourly emission limitations for PM, PM<sub>10</sub>, SO<sub>2</sub>, NO<sub>x</sub>, CO and VOC from carbon furnace #1. The limitations are to ensure the facility demonstrates compliance with Title 129, Chapters 4 and 19. The facility has performed stack testing on this unit, which demonstrates compliance with these emission limits.
- (5) Hourly emission limitations for PM, PM<sub>10</sub>, SO<sub>2</sub>, NO<sub>x</sub>, CO and VOC from carbon furnace #2. The limitations are to ensure the facility demonstrates compliance with Title 129, Chapters 4 and 19. The facility has performed stack testing on this unit, which demonstrates compliance with these emission limits.

#### XIII.(J) Requirements for Natural Gas Boilers 1-5

- (1) Fuel type limitation for the boilers to demonstrate compliance with Title 129, Chapters 4 and 19.
- (2) Low-NO<sub>x</sub> burner replacement requirement for Boiler #1 to comply with the Consent Decree.
- (3) Hourly emission limitations for NO<sub>x</sub> and CO from the boilers. The limitations are to ensure the facility demonstrates compliance with Title 129, Chapters 4 and 19. A CEMS is required to monitor NO<sub>x</sub> emissions, and CO emissions are based on established, AP-42 emission factors. Therefore, no additional stack testing is required for these units.
- (4) NSPS, Subpart Db requirements for the boilers.
- (5) This condition contains the requirements of 40 CFR 63, Subpart DDDDD (Industrial-Commercial-Institutional Steam Generating Units) applicable to existing Boilers #1-4.
- (6) This condition contains the requirements of 40 CFR 63, Subpart DDDDD (Industrial-Commercial-Institutional Steam Generating Units) applicable to the new Boiler #5.

#### XIII.(K) Requirements for the Coal-Fired Boilers

- (1) Fuel type limitation for the boilers to demonstrate compliance with Title 129, Chapters 4 and 19.
- (2) Control device requirements for the boilers to demonstrate compliance with Title 129, Chapters 4 and 19.
- (3) The source shall follow the manufacturer's manual or create their own manual detailing how to properly operate, inspect, and maintain the dry dust collectors (baghouses) and pressure differential indicator. Pressure drop monitoring in conjunction with continuous opacity monitoring will ensure the dry dust collectors are working properly. Emission calculations in this permit rely on the use of properly operated and well-maintained dry dust collectors.
- (4) Emission limitations for PM, PM<sub>10</sub>, NO<sub>x</sub>, SO<sub>2</sub>, CO, VOC, Fluoride, H<sub>2</sub>SO<sub>4</sub>, and Lead (Pb) from the boilers. Hourly emission limitations are included for SO<sub>2</sub> and CO that apply at all times in order to ensure compliance with the NAAQS. The limitations are to ensure the facility demonstrates compliance with Title 129, Chapters 4 and 19, and also demonstrate compliance with the NSPS requirements for PM, NO<sub>x</sub>, and SO<sub>2</sub> in Condition XIII.(K)(7). The SO<sub>2</sub> emission limit will vary depending on input sulfur content, as described in Condition XIII.(K)(5).



- (5) This condition identifies how the rolling 30-day SO<sub>2</sub> emission limit is calculated. The emission limit is calculated by the average of 30 individual values derived by fuel analysis over 30 consecutive boiler operating days.
- (6) Requires the facility to conduct stack testing to demonstrate compliance with the hourly limitations in Condition XIII.(K)(4) for those pollutant not monitored using a CEMS. As the facility is allowed to burn multiple fuel types in these boilers (coal, TDF, petroleum coke, and/or biomass), PM/PM<sub>10</sub> and VOC testing must be performed using all possible fuel types. The performance testing for F (as HF), H<sub>2</sub>SO<sub>4</sub>, and Pb must be completed using the worst-case fuel for each pollutant (as determined by fuel analysis).
- (7) NSPS, Subpart Db requirements for the boilers.
- (8) This condition contains the requirements of 40 CFR 63, Subpart DDDDD (Industrial-Commercial-Institutional Steam Generating Units) applicable to the CFB boilers.

#### XIII.(L) Requirements for Coal, Fly Ash, Bed Ash, and Limestone Handling

- (1) Identifies the equipment used at this facility to handle and process coal, fly ash, bed ash, and limestone and their associated control devices to demonstrate compliance with Title 129, Chapters 4 and 19.
- (2) The source shall follow the manufacturer's manual or create their own manual detailing how to properly operate, inspect, and maintain the dry dust collectors (baghouses) and their pressure differential indicators. Emission calculations in this permit rely on the use of properly operated and well-maintained dry dust collectors.
- (3) PM and PM<sub>10</sub> hourly emission limitations on the coal, fly ash, bed ash, and limestone handling equipment to ensure the facility demonstrates compliance with Title 129, Chapters 4 and 19.
- (4) Requires the facility to conduct stack testing to demonstrate compliance with the hourly limitations in Condition XIII.(L)(3). In some cases, only one of a group of similar units is required to be tested, unless that test shows non-compliance with the emission limits, in which case all similar units must be tested.
- (5) Contains the requirements of 40 CFR, Part 60, Subpart Y (Coal Preparation Plants). Emission units EU9-2 and EU9-3 are not subject to this Subpart because they are not transfer/loading operations as defined in the Subpart.

#### XIII.(M) Requirements for the Cooling Towers

- (1) The source shall follow the manufacturer's manual or create their own manual detailing how to properly operate, inspect, and maintain the cooling tower. Emission calculations in this permit rely on the use of properly operated and well-maintained cooling tower.
- (2) Limitation on the drift loss percent from the cooling towers. The percent is the manufacturer's drift loss percent. If the cooling towers are properly maintained and operated (Condition XIII.(M)(1)), then the drift loss percent should be in compliance. The drift loss percent is used to calculate particulate matter emissions.
- (3) Limitation of total dissolved solids in water and requiring at least once a month sampling and testing of TDS in the circulation water. TDS amounts are used to calculate particulate matter emissions.

#### XIII.(N) Requirements for Equipment Leaks

- (1) NSPS, Subpart VV for equipment leaks. This condition requires a Leak Detection and Repair (LDAR) program to be conducted.

#### XIII.(O) Requirements for Haul Roads

- (1) This condition requires that all haul roads with production-related traffic (roads used to bring in and send out raw materials and products, roads related to equipment maintenance, etc.) be paved.
  - (a) The facility should develop and following their Truck Traffic Fugitive Control Strategy and Monitoring Plan to minimize emissions from haul roads.
    - (i) BMPs include frequent vacuum sweeping of the roads unless weather events deem road cleaning unnecessary. Weather events that may suspend the cleaning of the roads with the vacuum sweeper include events such as ice or snow covering on the roads or a precipitation event of greater than 0.1 inches of rain or snow. The facility should document the weather events that temporarily suspend the road cleaning.
    - (ii) Visible emissions are an indicator that the haul roads must be cleaned or have additional controls to prevent off-site transport of particulate matter. No visible emissions occurring during truck traffic movement on haul roads indicate that the controls methods are adequate to prevent airborne off-site transport of particulate matter.
    - (iii) Documentation requirements to demonstrate adherence to the Plan and BMPs

#### XIII.(P) Requirements for Emergency Equipment

- (1) Limitation on the operating hours of emergency equipment to demonstrate compliance with Title 129, Chapters 4, 19 and 27.
- (2) Fuel combusted in the engines is limited to diesel fuel (# 1 or # 2) to comply with Title 129, Chapters 4, 19, 20 (Section 002) and 24.
- (3) Hour meters are required to demonstrate compliance with Condition XIII.(P)(1).

#### XIII.(Q) Requirements for Wastewater Treatment

- (1) Biogas collected can only be combusted in the biogas flare or Gluten Flash Dryer #1, not in any other fuel fired equipment. Also, the biogas must be combusted, and not vented directly to the air.
- (2) The operating hours of the biogas flare are limited to 2,190 hrs/yr. The biogas will be mainly combusted in the dryer, with the flare as backup. The facility requested this limit to support their PSD BACT analysis for SO<sub>2</sub> emissions. The pilot for the flare can run continuously.
- (3) An hour meter(s) is required to demonstrate compliance with Condition XIII.(Q)(2).
- (4) Proper installation/operation, and routine inspection/maintenance of the equipment associated with the wastewater treatment operations.

#### XIII.(R) Requirements for the Soda Ash receiving and HCl storage and receiving operations

- (1) The condition requires the Soda Ash receiving and HCl storage and receiving operations to be controlled by scrubbers. This condition is to demonstrate compliance with Title 129, Chapters 19 and 27.
- (2) The source shall follow the manufacturer's manual or create their own manual detailing how to properly operate, inspect, and maintain each scrubber and its operating parameter indicator(s). Emission calculations in this permit rely on the use of properly operated and well-maintained scrubbers.
- (3) PM and PM<sub>10</sub> hourly emissions limitations for the Soda Ash receiving vent to ensure the facility demonstrates compliance with Title 129, Chapters 4 and 19.
- (4) Requires the facility to conduct a stack test to demonstrate compliance with the hourly limitations in Condition XIII.(R)(3).

XIII.(S) Requirements for the Lime silo bin vent

- (1) Requires the lime silo operations be controlled by a dry dust collector to demonstrate compliance with Title 129, Chapters 4 and 19.
- (2) The source shall follow the manufacturer's manual or create their own manual detailing how to properly operate, inspect, and maintain the dry dust collector and its operating parameter indicator(s). Emission calculations in this permit rely on the use of properly operated and a well-maintained dry dust collector.
- (3) PM and PM<sub>10</sub> hourly emission limitations on the lime silo bin vent to ensure the facility demonstrates compliance with Title 129, Chapters 4 and 19.
- (4) Requires the facility to conduct a stack test to demonstrate compliance with the emission limitations in Condition XIII.(S)(3).

XIII.(T) Requirements for Miscellaneous Organic NESHAP

- (1) This condition contains the requirements of 40 CFR 63, Subpart FFFF (Miscellaneous Organic Chemical Manufacturing) applicable to the ethanol manufacturing operations.

XIII.(U) Requirements to verify NAAQS modeling analyses. (Title 129, Chapter 4)

- (1) Stack height restrictions per modeling submittal.
- (2) The property must have restricted public access. The restriction plan shall be submitted to the NDEQ prior to start up of operations.
- (3) Requires a site survey (or other similar documentation) to demonstrate compliance with Condition XIII.(U)(1). This requirement applies to all new and modified stacks. ADM was required to conduct a source-wide survey of existing stacks as part of the 2001 permit issued for the new rail receiving stations.
- (4) Requires a site survey (or other similar documentation) to demonstrate compliance with Condition XIII.(U)(2).

XIII.(V) Stack testing requirements per Title 129, Chapter 34

- (1) Testing methods may be from 40 CFR 60 Appendix A, or other NDEQ approved testing method. The individual emission points that are required to test for VOC and HAPs will have to conduct a control efficiency test (inlet & outlet testing) to ensure that the HAP BACT is appropriate for the emission unit.

XIII.(W) Requirements for the Monitoring and Related Recordkeeping and Reporting Requirements

- (1) Inspection and maintenance records for each baghouse.
- (2) Inspection and maintenance records for each scrubber.
- (3) NSPS, Subpart Kb recordkeeping and reporting requirements for the storage tanks.
- (4) Inspection and maintenance records for the liquid product loadout vapor recovery system and flare.
- (5) Records indicating when the burner on Boiler #1 was replaced.
- (6) NSPS, Subpart Db recordkeeping and reporting requirements.
- (7) Fuel receipts demonstrating the types of fuels used at the facility.
- (8) NESHAP, Subpart DDDDD recordkeeping requirements.
- (9) Operation and maintenance records for the cooling towers.
- (10) Manufacturer's drift loss guarantee for the cooling towers.
- (11) Sample testing results for TDS.
- (12) NSPS, Subpart VV recordkeeping and reporting requirements for the equipment leaks.
- (13) Fugitive dust control methods including fugitive dust control plan, and documentation of implementation of control methods.
- (14) Visible checks of the haul roads and any corrective action taken.
- (15) Monthly and rolling 12-month records for emergency equipment operating hours.

- (16) Monthly and rolling 12-month records for operating hours of the biogas flare.
- (17) Inspection and maintenance records for the wastewater treatment tanks and biogas flare.
- (18) NESHAP, Subpart FFFF recordkeeping and reporting requirements.
- (19) Site survey to show compliance with NAAQS modeling requirements.
- (20) Calibration records for all operating parameter monitoring equipment.
- (21) Copies of all documentation (notifications, reports, plans, and test results) submitted to NDEQ.
- (22) Manufacturer's documentation (design, installation, operation, maintenance) and maintenance records for all equipment.

**STATUTORY OR REGULATORY PROVISIONS ON WHICH PERMIT REQUIREMENTS ARE BASED:**

Applicable regulations: Title 129 - Nebraska Air Quality Regulations as amended March 14, 2006.

**PROCEDURES FOR FINAL DETERMINATION WITH RESPECT TO THE PROPOSED CONSTRUCTION PERMIT:**

The public notice, as required under NAQR Chapter 14, shall be published on May 23, 2006, in the Columbus Telegram newspaper. Persons or groups shall have 30 days from that issuance of public notice (June 21, 2006) to provide the NDEQ with any written comments concerning the proposed permit action and/or to request a public hearing, in accordance with NAQR Chapter 14. If a public hearing is granted by the Director, there will be a notice of that meeting published at least 30 days prior to the hearing. Persons having comments or requesting a public hearing may contact:

W. Clark Smith-Permitting Section Supervisor  
Air Quality Division  
Nebraska Department of Environmental Quality  
PO Box 98922  
Lincoln, Nebraska 68509-8922

If no public hearing is requested, the permit may be granted at the close of the 30-day comment period. If a public hearing is requested, the Director of the NDEQ may choose to extend the date on which the permit is to be granted until after that public hearing has been held. During the 30-day comment period, persons requiring further information should contact:

W. Clark Smith-Permitting Section Supervisor  
Air Quality Division  
Nebraska Department of Environmental Quality  
PO Box 98922  
Lincoln, Nebraska 68509-8922

**Telephone inquiries may be made at:**

(402) 471-2189

**TDD users please call 711 and ask the relay operator to call us at (402) 471-2186.**

## **Appendix A - Emission Calculations**

**Appendix A: Emission Calculations**  
**Emission Unit Descriptions**

Significant Emission Units				
Emission Unit ID	Stack/Vent (SV #)	Description	Add-on Control Device	CP Date
EU1-1	1	Corn Receiving (E)	Baghouse	9/19/1991
EU1-2	2	Corn Receiving (W)	Baghouse	9/19/1991
EU2-3	3	Corn Cleaner/Fines Bin	Baghouse	9/19/1991
EU2-4	4	Corn Cleaner	Baghouse	7/3/2001
EU3-5	5	Millhouse/Feedhouse	Scrubber	9/19/1991
EU4-6	6	Starch Dryer # 1	Scrubber	9/19/1991
EU5-7A	7	Germ Dryer # 1	Scrubber	9/19/1991
EU5-7B	7	Germ Dryer # 2	Scrubber	9/19/1991
EU5-7C	7	Germ Dryer # 3	Scrubber	9/19/1991
EU5-8	8	Fluidized Bed Germ Dryer #1	Scrubber	7/12/1995
EU5-9A	9	Germ Cooler # 1	Baghouse	9/19/1991
EU5-9B	9	Germ Cooler # 2	Baghouse	9/19/1991
EU5-9C	9	Germ Cooler # 3	Baghouse	9/19/1991
EU5-12	12	Germ Cooler # 4	Baghouse	9/19/1991
EU6-16	16	Gluten Flash Dryer # 1	Scrubber	1/10/1994
EU6-17	17	Gluten Cooler # 1	Baghouse	1/10/1994
EU6-18	18	Gluten Flash Dryer # 2	Scrubber	7/12/1995
EU6-19	19	Gluten Cooler # 2	Baghouse	1/10/1994
EU4-20	20	Starch Storage Bin # 11	Baghouse	9/19/1991
EU4-21	21	Starch Storage Bin # 12	Baghouse	9/19/1991
EU4-22	22	Starch Storage Bin # 9	Baghouse	9/19/1991
EU4-23	23	Starch Storage Bin # 10	Baghouse	9/19/1991
EU5-24	24	Gluten Storage Bin # 7	Baghouse	9/19/1991
EU5-25	25	Gluten Storage Bin # 8	Baghouse	9/19/1991
EU5-26	26	Gluten Storage Bin # 5	Baghouse	9/19/1991
EU5-27	27	Gluten Storage Bin # 6	Baghouse	9/19/1991
EU6-28	28	Germ Storage Bin # 3	Baghouse	9/19/1991
EU6-29	29	Germ Storage Bin # 4	Baghouse	9/19/1991
EU6-30	30	Germ Storage Bin # 1	Baghouse	9/19/1991
EU6-31	31	Germ Storage Bin # 2	Baghouse	9/19/1991
EU7-32	32	Fermentation CO <sub>2</sub> Scrubber (east)	Scrubber	9/19/1991
EU7-33	33	Fermentation CO <sub>2</sub> Scrubber (west)	Scrubber	9/19/1991
EU7-34	34	Distillation & Dehydration VB Scrubber	Scrubber	9/19/1991
EU8-35	35	Carbon Furnace # 1	Scrubber	1/10/1994
EU8-36	36	Carbon Furnace # 2	Scrubber	7/12/1995
EU9-38	38	Natural Gas Boiler # 1	None	9/19/1991
EU9-39	39	Natural Gas Boiler # 2	None	1/10/1994
EU9-40	40	Natural Gas Boiler # 3	None	7/12/1995
EU9-41	40	Natural Gas Boiler # 4	None	7/12/1995
EU10-41	41	Anaerobic Digester Biogas flare	Flare	10/20/1993
EU2-42	42	Corn Fines Transfer	Baghouse	9/19/1991
EU11-43	43	Fiber Dewatering	None	9/19/1991
EU6-44	44	Gluten Recycle	Baghouse	9/19/1991
EU4-45	45	Starch Dryer #2	Scrubber	12/23/1999
EU4-46	46	Starch Bin #13	Baghouse	12/23/1999
EU4-47	47	Starch Bin #14	Baghouse	12/23/1999
EU4-48	48	Starch Dryer Loadout	Baghouse	12/23/1999
EU1-54	54	Corn Silo #1	Baghouse	

EU1-55	55	Corn Silo #2	Baghouse	
EU1-56	56	Corn Silo #3	Baghouse	
EU1-57	57	Corn Silo #4	Baghouse	
EU1-58	58	Corn Silo #5	Baghouse	
EU1-59	59	Corn Silo #6	Baghouse	
EU1-60	60	Corn Silo #7	Baghouse	
EU1-61	61	Corn Silo #8	Baghouse	

**Appendix A: Emission Calculations**  
**Emission Unit Descriptions**

Significant Emission Units				
Emission Unit ID	Stack/Vent (SV #)	Description	Add-on Control Device	CP Date
EU13-62	62	Lime Silo Bin	Baghouse	9/19/1991
EU8-63	63	Soda Ash Receiving	Scrubber	9/19/1991
EU6-66	66	Gluten RVF (SE)	Scrubber	
EU6-67	67	Gluten RVF (SW)	Scrubber	
EU6-68	68	Gluten RVF (NW)	Scrubber	
EU12-69	69	Stillage/Steepwater Evaporator (E)	Scrubber	
EU12-70	70	Stillage/Steepwater Evaporator (W)	Scrubber	
EU14-71	71	Rail Corn Storage and Handling	Baghouse	7/3/2001
EU14-72	72	Corn Storage Bin 9A	Baghouse	7/3/2001
EU14-73	73	Corn Storage Bin 9B	Baghouse	7/3/2001
EU14-74	74	Corn Storage Bin 10A	Baghouse	7/3/2001
EU14-75	75	Corn Storage Bin 10B	Baghouse	7/3/2001
EU14-76	76	Corn Storage Bin 11A	Baghouse	7/3/2001
EU14-77	77	Corn Storage Bin 11B	Baghouse	7/3/2001
EU14-78	78	Corn Storage Bin 12A	Baghouse	7/3/2001
EU14-79	79	Corn Storage Bin 12B	Baghouse	7/3/2001
EU14-80	80	Corn Storage Bin 13A	Baghouse	7/3/2001
EU14-81	81	Corn Storage Bin 13B	Baghouse	7/3/2001
EU14-82	82	Corn Storage Bin 14A	Baghouse	7/3/2001
EU14-83	83	Corn Storage Bin 14B	Baghouse	7/3/2001
EU14-84	84	Corn Storage Bin 15A	Baghouse	7/3/2001
EU14-85	85	Corn Storage Bin 15B	Baghouse	7/3/2001
EU14-86	86	Corn Storage Bin 16A	Baghouse	7/3/2001
EU14-87	87	Corn Storage Bin 16B	Baghouse	7/3/2001
EU14-88	88	Corn Storage Bin 17A	Baghouse	7/3/2001
EU14-89	89	Corn Storage Bin 17B	Baghouse	7/3/2001
EU7-90	90	Liquid Product Loadout	Flare	9/19/1991
EU8-91	91	HCl Storage Tank Scrubber	Scrubber	
EU12-92	92	Heavy Steepwater Tank 1	None	
EU12-93	93	Heavy Steepwater Tank 2	None	
EU12-94	94	Heavy Steepwater Tank 3	None	
EU14-105	105	Rail Corn Silo #1	Baghouse	
EU14-106	106	Rail Corn Silo #2	Baghouse	
EU9-98	98	Natural Gas Boiler # 5	None	
EU-99	99	Emergency Generator - Warehouse 1	None	
EU10-100	100	Process Waste Tank #1	None	
EU10-101	101	Process Waste Tank #2	None	
EU10-102	102	Process Waste Tank #3	None	
EU12-103	103	Light Steepwater Tank	None	
EU7-104	104	Sterile Steepwater Tank	None	
EU9-1A	COGEN1A	Coal-fired boiler #1	Baghouse	
EU9-1B	COGEN1B	Coal-fired boiler #2	Baghouse	
EU9-2	COGEN2	Rotary Car Dumper/Truck Dump Building Unit 1	Baghouse	
EU9-3	COGEN3	Rotary Car Dumper/Truck Dump Building Unit 2	Baghouse	
EU9-4	COGEN4	Coal Storage Dome/Reclaim Tunnel	Baghouse	
EU9-5	COGEN5	Crusher Tower	Baghouse	
EU9-6	COGEN6	Powerhouse Bunker Bay	Baghouse	
EU9-7	COGEN7	Fly Ash Transfer/Storage Unit 1	Baghouse	



EU9-8	COGEN8	Fly Ash Transfer/Storage Unit 2	Baghouse	
EU9-9	COGEN9	Bottom Ash Collection Unit 1	Baghouse	
EU9-10	COGEN10	Bottom Ash Collection Unit 2	Baghouse	
EU9-11	COGEN11	Bottom Ash Transfer/Storage Unit 1	Baghouse	
EU9-12	COGEN12	Bottom Ash Transfer/Storage Unit 2	Baghouse	
EU9-13	COGEN13	Limestone Storage Unit 1	Baghouse	
EU9-14	COGEN14	Limestone Storage Unit 2	Baghouse	

## Appendix A: Emission Calculations

### Emission Unit Descriptions

Significant Emission Units				
Emission Unit ID	Stack/Vent (SV #)	Description	Add-on Control Device	CP Date
EU9-15	COGEN15	Limestone Transfer Unit 1	Baghouse	
EU9-16	COGEN16	Limestone Transfer Unit 2	Baghouse	
EU9-17-18	COGEN 17-18	CoGeneration Cooling Towers Unit #1	None	
EU9-19-22	COGEN 19-22	CoGeneration Cooling Towers Unit #2	None	
EQ_LKS_FUG	EQ_LKS_FUG	Equipment Leaks	None	9/19/1991
EU13-E1-6	SETHA 1-6	Ethanol Cooling Towers	None	NA
EU13-F1-3	SFRUC 1-3	Fructose Cooling Towers	None	NA
EU7-TK01	TK-01	Day Tank A - Ethanol	None	9/19/1991
EU7-TK02	TK-02	Day Tank B - Ethanol	None	9/19/1991
EU7-TK03	TK-03	Rerun Tank - Ethanol	None	9/19/1991
EU7-TK04	TK-04	Day Tank C - Ethanol	None	9/19/1991
EU7-TK05	TK-05	Denaturant Tank	None	9/19/1991
EU7-TK06	TK-06	Denatured Ethanol Tank	None	7/12/1995
EU7-TK07	TK-07	Corrosion Inhibitor Tank	None	9/19/1991
EU7-TK08	TK-08	Denaturant Tank	None	
TRUCK_FUG	TRUCK_FUG	Fugitive Particulate (Roads)	None	9/19/1991
WETFEED_FUG	WETFEED_FUG	Wet Feed Pile	None	NA
WWTP_FUG	WWTP_FUG	Wastewater Treatment Fugitives	None	
COAL_FUG	COAL_FUG	Coal Receiving Fugitives	None	
GRN_FUG	GRN_FUG	Grain Receiving Fugitives	None	
WWTP_TNKS	WWTP_TNKS	Equalization Tanks	None	
EU-97	97	Emergency Generator - SCU (10 HP)	None	
EU-95	95	Fire Pump #1 (235 HP)	None	
EU-96	96	Fire Pump #2 (130 HP)	None	
EU-107	107	Fire Pump #3 (375 HP)	None	
EU-108	108	Fire Pump #4 (375 HP)	None	

### Emission Unit Descriptions (Miscellaneous Units)

Description		
8 Propane Space Heaters less than 0.32 MMBtu/hr each		
7 Natural Gas Space Heaters less than 0.16 MMBtu/hr each		
23 Storage Tanks, each less than 16,000 gallons		

**Appendix A: Emission Calculations**  
**Criteria Pollutant Emission Summary (tons/yr)**

SV#	Description	PM	PM <sub>10</sub>	NO <sub>x</sub>	SO <sub>2</sub>	H <sub>2</sub> SO <sub>4</sub>	CO	VOC
1	Corn Receiving (E)	2.29	2.29					
2	Corn Receiving (W)	2.29	2.29					
3	Corn Cleaner/Fines Bin	0.44	0.44					
4	Corn Cleaner	2.29	2.29					
5	Millhouse/Feedhouse	17.04	17.04		29.57			21.20
6	Starch Dryer # 1	13.27	13.27					
7	Germ Dryers # 1, 2, 3	34.21	16.73		37.23			100.74
8	Fluidized Bed Germ Dryer #1	13.14	13.14	14.45	2.23		17.61	6.57
9	Germ Cooler # 1 <sup>a</sup>	3.22	3.22					22.34
9	Germ Cooler # 2 <sup>a</sup>	3.36	3.36					
9	Germ Cooler # 3 <sup>a</sup>	2.35	2.35					
12	Germ Cooler # 4	6.80	6.80					28.47
16	Gluten Flash Dryer # 1	76.70	35.04	19.05	28.91		66.58	99.86
17	Gluten Cooler # 1	5.47	5.47					9.11
18	Gluten Flash Dryer # 2	43.14	19.71	17.08	10.51		20.76	97.24
19	Gluten Cooler # 2	6.93	6.93					11.48
20	Starch Storage Bin # 11	0.14	0.14					
21	Starch Storage Bin # 12	0.14	0.14					
22	Starch Storage Bin # 9	0.14	0.14					
23	Starch Storage Bin # 10	0.14	0.14					
24	Gluten Storage Bin # 7	0.14	0.14					
25	Gluten Storage Bin # 8	0.14	0.14					
26	Gluten Storage Bin # 5	0.14	0.14					
27	Gluten Storage Bin # 6	0.14	0.14					
28	Germ Storage Bin # 3	0.14	0.14					
29	Germ Storage Bin # 4	0.14	0.14					
30	Germ Storage Bin # 1	0.14	0.14					
31	Germ Storage Bin # 2	0.14	0.14					
32	Fermenters, Distillation Scrubbers (SV 32-34)				10.95			59.13
35	Carbon Furnace # 1	8.23	4.38	14.80	8.76		33.42	11.83
36	Carbon Furnace # 2	13.75	6.57	24.70	14.45		35.65	16.64
38	Natural Gas Boiler # 1 <sup>b</sup>	24.35	24.35	38.11	1.92		269.16	17.62
39	Natural Gas Boiler # 2 <sup>b</sup>			77.79				
40	Natural Gas Boiler # 3 <sup>b</sup>			58.54				
40	Natural Gas Boiler # 4 <sup>b</sup>			58.54				
41	Anaerobic Digester Biogas flare	0.09	0.09	1.14	55.85		0.96	0.06
42	Corn Fines Transfer	0.19	0.19					
43	Fiber Dewatering	2.76	2.76		17.78			6.66
44	Gluten Recycle	0.46	0.46					0.88
45	Starch Dryer #2	13.27	13.27					
46	Starch Bin #13	0.27	0.27					
47	Starch Bin #14	0.27	0.27					
48	Starch Dryer Loadout	0.48	0.48					
54	Corn Silo #1	0.07	0.07					
55	Corn Silo #2	0.07	0.07					
56	Corn Silo #3	0.07	0.07					
57	Corn Silo #4	0.09	0.09					
58	Corn Silo #5	0.09	0.09					
59	Corn Silo #6	0.09	0.09					
60	Corn Silo #7	0.09	0.09					
61	Corn Silo #8	0.09	0.09					
62	Lime Silo Bin	0.55	0.55					
63	Soda Ash Receiving	0.37	0.37					
66	Gluten RVF (SE) <sup>c</sup>				0.18			0.88
67	Gluten RVF (SW) <sup>c</sup>				0.18			0.88
68	Gluten RVF (NW) <sup>c</sup>				0.09			0.44
69	Stillage/Steepwater Evaporator (E) <sup>c</sup>				40.73			213.74
70	Stillage/Steepwater Evaporator (W) <sup>c</sup>				48.62			208.05
71	Rail Corn Storage and Handling	3.61	3.61					
72	Corn Storage Bin 9A	0.08	0.08					
73	Corn Storage Bin 9B	0.08	0.08					

74	Corn Storage Bin 10A	0.08	0.08					
75	Corn Storage Bin 10B	0.08	0.08					
76	Corn Storage Bin 11A	0.08	0.08					

<sup>a</sup> VOC estimate combined for Germ Cooling Baghouses 1-3.

<sup>b</sup> PM/PM<sub>10</sub>, SO<sub>2</sub>, CO, and VOC estimates combined for Boilers 1-4.

<sup>c</sup> Emission estimates for SV 66-70 are uncontrolled emissions and are not included in the total as controlled emissions from these units are included in the the millhouse scrubber system estimate (SV-5).

**Appendix A: Emission Calculations**  
**Criteria Pollutant Emission Summary (tons/yr)**

SV#	Description	PM	PM10	NOx	SO <sub>2</sub>	H <sub>2</sub> SO <sub>4</sub>	CO	VOC
77	Corn Storage Bin 11B	0.08	0.08					
78	Corn Storage Bin 12A	0.08	0.08					
79	Corn Storage Bin 12B	0.08	0.08					
80	Corn Storage Bin 13A	0.08	0.08					
81	Corn Storage Bin 13B	0.08	0.08					
82	Corn Storage Bin 14A	0.08	0.08					
83	Corn Storage Bin 14B	0.08	0.08					
84	Corn Storage Bin 15A	0.08	0.08					
85	Corn Storage Bin 15B	0.08	0.08					
86	Corn Storage Bin 16A	0.08	0.08					
87	Corn Storage Bin 16B	0.08	0.08					
88	Corn Storage Bin 17A	0.08	0.08					
89	Corn Storage Bin 17B	0.08	0.08					
90	Liquid Product Loadout	0.37	0.37	1.05	0.01		2.63	4.50
92-94	Heavy Steepwater Tanks #1-3				0.16			0.70
105	Rail Corn Silo #1	1.69	1.69					
106	Rail Corn Silo #2	3.94	3.94					
98	Natural Gas Boiler # 5	8.16	8.16	39.42	0.64		103.37	5.90
95, 96, 97, 99, 108, 109	4 Emergency Generators and 2 Fire Pumps	0.52	0.52	7.37	0.48		1.59	0.60
100-102	Process Waste Tanks #1-3							3.48
103	Light Steepwater Tank							2.65
104	Sterile Steepwater Tank							5.52
COAL_FUG	Coal Receiving Fugitives	1.05	0.32					
COGEN1A/1B	Coal-fired boiler Nos. 1 and 2	185.01	168.19	470.94	1,345.54	67.28	672.77	47.09
COGEN2	Rotary Car Dumper/Truck Dump Building Unit 1	3.10	3.10					
COGEN3	Rotary Car Dumper/Truck Dump Building Unit 2	3.10	3.10					
COGEN4	Coal Storage Dome/Reclaim Tunnel	2.96	2.96					
COGEN5	Crusher Tower	2.22	2.22					
COGEN6	Powerhouse Bunker Bay	2.40	2.40					
COGEN7	Fly Ash Transfer/Storage Unit 1	1.05	1.05					
COGEN8	Fly Ash Transfer/Storage Unit 2	1.05	1.05					
COGEN9	Bottom Ash Collection Unit 1	0.35	0.35					
COGEN10	Bottom Ash Collection Unit 2	0.35	0.35					
COGEN11	Bottom Ash Transfer/Storage Unit 1	0.35	0.35					
COGEN12	Bottom Ash Transfer/Storage Unit 2	0.35	0.35					
COGEN13	Limestone Storage Unit 1	0.92	0.92					
COGEN14	Limestone Storage Unit 2	0.92	0.92					
COGEN15	Limestone Transfer Unit 1	0.92	0.92					
COGEN16	Limestone Transfer Unit 2	0.92	0.92					
COGEN17-18	CoGeneration Cooling Towers Unit #1	0.08	0.05					
COGEN19-22	CoGeneration Cooling Towers Unit #2	0.93	0.56					
EQ_LKS_FUG	Equipment Leaks							24.60
GRN_FUG	Grain Receiving Fugitives	0.60	0.16					
SETHA 1-6	Ethanol Cooling Towers	20.85	14.24					
SFRUC 1-3	Fructose Cooling Towers	8.33	5.70					
TK-01	Day Tank A - Ethanol							0.33
TK-02	Day Tank B - Ethanol							0.33
TK-03	Rerun Tank - Ethanol							0.11
TK-04	Day Tank C - Ethanol							0.52
TK-05	Denaturant Tank							0.83
TK-06	Denatured Ethanol Tank							0.79
TK-07	Corrosion Inhibitor Tank							0.005
TK-08	Denaturant Tank							1.10
TRUCK_FUG	Fugitive Particulate (Roads)	33.47	6.53					
WETFEED_FUG	Wet Feed Pile	0.05	0.05		4.16			37.89
WWTP_FUG	Wastewater Treatment Fugitives							0.71
WWTP_TNKS	Equalization Tanks							2.77
<b>TOTAL<sup>c</sup></b>		<b>589.03</b>	<b>440.84</b>	<b>842.97</b>	<b>1,569.16</b>	<b>67.28</b>	<b>1,224.49</b>	<b>650.27</b>

Appendix A: Emission Calculations  
HAP Emission Summary (tons/yr)

Pollutant	CAS #	Gluten Flash Dryers #1 & 2	Fluidized Bed Germ Dryer #1	Storage Tanks	Liquid Product Loadout	Carbon Furnaces #1 and #2	Natural Gas Boilers # 1-4	Natural Gas Boiler #5	Coal-fired CFB Boilers	Emergency Generators & Fire Pumps	Biogas flare	HCL Storage Tank Scrubber	Total HAP
Acetaldehyde	75070			1.66E-02	3.11E-04				2.26E-01	1.28E-03			2.44E-01
Acetaophenone	98862								5.94E-03				5.94E-03
Acrolein	107028								1.15E-01	1.54E-04			1.15E-01
Antimony Compounds									7.12E-03				7.12E-03
Arsenic Compounds		9.45E-05	4.72E-05		2.41E-06	2.19E-05	6.41E-04	2.15E-04	1.62E-01		2.19E-06		1.63E-01
Benzene	71432	9.92E-04	4.96E-04	9.74E-03	8.05E-03	2.30E-04	6.73E-03	2.25E-03	5.14E-01	1.56E-03	2.30E-05		5.45E-01
Benzyl chloride	100447								2.77E-01				2.77E-01
Beryllium Compounds		5.67E-06	2.83E-06		1.45E-07	1.31E-06	3.85E-05	1.29E-05	8.31E-03		1.31E-07		8.37E-03
Bis(2-ethylhexyl)phthalate	117817								2.89E-02				2.89E-02
Bromoform	75252								1.54E-02				1.54E-02
1,3-Butadiene	106990									6.53E-05			6.53E-05
Cadmium Compounds		5.20E-04	2.60E-04		1.33E-05	1.20E-04	3.52E-03	1.18E-03	2.02E-02		1.20E-05		2.58E-02
Carbon Disulfide	75150				6.42E-05				5.14E-02				5.15E-02
2-Chloroacetophenone	532274								2.77E-03				2.77E-03
Chlorobenzene	108907								8.71E-03				8.71E-03
Chloroform	67663								2.33E-02				2.33E-02
Chromium Compounds		6.61E-04	3.31E-04		1.69E-05	1.53E-04	4.49E-03	1.50E-03	1.03E-01		1.53E-05		1.10E-01
Cobalt Compounds		3.97E-05	1.98E-05		1.01E-06	9.20E-06	2.69E-04	9.02E-05	3.96E-02		9.20E-07		4.00E-02
Cumene	98828			4.58E-04	3.21E-04				2.10E-03				2.88E-03
Cyanide Compounds									9.89E-01				9.89E-01
Dichlorobenzene	25321226	5.67E-04	2.83E-04		1.45E-05	1.31E-04	3.85E-03	1.29E-03			1.31E-05		6.14E-03
Dimethyl Sulfate	77781								1.90E-02				1.90E-02
2,4-Dinitrotoluene	121142								1.11E-04				1.11E-04
Ethyl benzene	100414			1.58E-03	1.60E-04				3.72E-02				3.89E-02
Ethyl chloride	75003								1.66E-02				1.66E-02
Ethylene Dibromide	106934								4.75E-04				4.75E-04
Ethylene Dichloride	107062								1.58E-01				1.58E-01
Formaldehyde	50000	3.54E-02	1.77E-02		9.05E-04	8.21E-03	2.40E-01	8.05E-02	9.50E-02	1.97E-03	8.21E-04		4.81E-01
Hexane	110543	8.50E-01	4.25E-01	8.51E-03	1.82E-01	1.97E-01	5.77E+00	1.93E+00	2.65E-02		1.97E-02		9.41E+00
Hydrochloric Acid	7647010								1.35E+02			6.31E-04	1.35E+02
Hydroflouric Acid	7664393								8.07E+00				8.07E+00
Isophorone	78591								2.30E-01				2.30E-01
Lead Compounds		2.36E-04	1.18E-04		6.03E-06	5.48E-05	1.60E-03	5.37E-04	1.35E+00		5.48E-06		1.35E+00
Manganese Compounds		1.79E-04	8.97E-05		4.58E-06	4.16E-05	1.22E-03	4.08E-04	1.94E-01		4.16E-06		1.96E-01
Mercury Compounds		1.23E-04	6.14E-05		3.14E-06	2.85E-05	8.33E-04	2.79E-04	2.02E-02		2.85E-06		2.15E-02
Methanol	67561			6.07E-03	3.11E-04								6.38E-03
Methyl Bromide	74839								6.33E-02				6.33E-02
Methyl Chloride	74873								2.10E-01				2.10E-01
Methyl Chloroform	71556								7.91E-03				7.91E-03
Methyl Ethyl Ketone	78933								1.54E-01				1.54E-01
Methyl Hydrazine	60344								6.73E-02				6.73E-02
Methyl Methacrylate	80626								7.91E-03				7.91E-03
Methyl tert Butyl Ether	1634044								1.39E-02				1.39E-02
Methylene Chloride	75092								1.15E-01				1.15E-01
Naphthalene	91203	2.88E-04	1.44E-04		7.36E-06	6.68E-05	1.95E-03	6.55E-04	5.14E-03	1.42E-04	6.68E-06		8.41E-03
Nickel Compounds		9.92E-04	4.96E-04		2.53E-05	2.30E-04	6.73E-03	2.25E-03	1.11E-01		2.30E-05		1.22E-01
Phenol	108952								6.33E-03				6.33E-03
Polycyclic Organic Hydrocarbons (POM)		4.17E-05	2.08E-05		1.06E-06	9.66E-06	2.83E-04	9.47E-05	3.07E-03	2.81E-04	9.66E-07		3.80E-03
Propionaldehyde	123386								1.50E-01				1.50E-01
Selenium compounds		1.13E-05	5.67E-06		2.90E-07	2.63E-06	7.69E-05	2.58E-05	5.14E-01		2.63E-07		5.15E-01
Styrene	100425								9.89E-03				9.89E-03
Tetrachloroethylene	127184								1.70E-02				1.70E-02
Toluene	108883	1.61E-03	8.03E-04	1.40E-02	1.61E-02	3.72E-04	1.09E-02	3.65E-03	9.50E-02	6.83E-04	2.07E-02		1.64E-01
1,2,4-Trimethyl benzene	120821			1.97E-03									1.97E-03
2,2,4-Trimethyl pentane	540841			1.14E-02									1.14E-02
Vinyl Acetate	108054								3.01E-03				3.01E-03
Xylene	1330207			7.43E-03	1.60E-03				1.46E-02	4.76E-04			2.42E-02
Total All HAPs:													158.90

**Appendix A: Emission Calculations**
**Process Weight Rate**
**Title 129, Chapter 20, Section 001**

For process weight rates up to 60,000 lbs/hr (30 tons/hr):

$$E = 4.10 p^{0.67}$$

For process weight rates in excess of 60,000 lbs/hr (30 tons/hr):

$$E = 55.0 p^{0.11} - 40$$

where E = rate of emissions in lbs/hr PM and p = process weight rate in tons/hr.

SV#	Unit Description	P (tons/hr)	E (lbs/hr)	Unit Emission Rate (lbs/hr)
1	Corn Receiving (E)	560	70.32	0.52
2	Corn Receiving (W)	560	70.32	0.52
3	Corn Cleaner/Fines Bin	45	43.60	0.10
4	Corn Cleaner	28	38.23	0.52
5	Millhouse/Feedhouse	280	62.22	3.89
6	Starch Dryer # 1	12.5	22.27	3.03
7	Germ Dryers #1, 2, 3	11.8	21.43	7.81
9	Germ Cooler # 1	5	12.05	0.73
9	Germ Cooler # 2	5	12.05	0.77
9	Germ Cooler # 3	5	12.05	0.54
12	Germ Cooler # 4	15	25.16	1.55
16	Gluten Flash Dryer #1	7.5	15.82	17.51
17	Gluten Cooler # 1	7.5	15.82	1.25
18	Gluten Flash Dryer #2	7.5	15.82	9.85
19	Gluten Cooler # 2	7.5	15.82	1.58
20	Starch Storage Bin #11	12.5	22.27	0.03
21	Starch Storage Bin #12	12.5	22.27	0.03
22	Starch Storage Bin # 9	12.5	22.27	0.03
23	Starch Storage Bin #10	12.5	22.27	0.03
24	Gluten Storage Bin # 7	22	32.52	0.03
25	Gluten Storage Bin # 8	22	32.52	0.03
26	Gluten Storage Bin # 5	22	32.52	0.03
27	Gluten Storage Bin # 6	22	32.52	0.03
28	Germ Storage Bin # 3	15	25.16	0.03
29	Germ Storage Bin # 4	15	25.16	0.03
30	Germ Storage Bin # 1	15	25.16	0.03
31	Germ Storage Bin # 2	15	25.16	0.03
35	Carbon Furnace # 1	0.9375	3.93	1.88
36	Carbon Furnace # 2	1.56	5.53	3.14
42	Corn Fines Transfer	42	42.97	0.04
43	Fiber Dewatering	22	32.52	0.63
44	Gluten Recycle	7	15.10	0.11
45	Starch Dryer # 2	12.5	22.27	3.03
46	Starch Bin #13	13	22.86	0.06
47	Starch Bin #14	13	22.86	0.06
48	Starch Dryer Loadout	2	6.52	0.11
54	Corn Silo #1	1,120	79.06	0.02
55	Corn Silo #2	1,120	79.06	0.02
56	Corn Silo #3	1,120	79.06	0.02
57	Corn Silo #4	1,120	79.06	0.02
58	Corn Silo #5	1,120	79.06	0.02
59	Corn Silo #6	1,120	79.06	0.02
60	Corn Silo #7	1,120	79.06	0.02
61	Corn Silo #8	1,120	79.06	0.02
62	Lime Silo Bin	30	40.04	0.13
63	Soda Ash Receiving	30	40.04	0.08

**Appendix A: Emission Calculations**  
**Title 129, Chapter 20, Section 001**

**Process Weight Rate (continued)**

SV#	Unit Description	P (tons/hr)	E (lbs/hr)	Unit Emission Rate (lbs/hr)
71	Rail Corn Storage and Handling	14	24.03	0.82
72	Corn Storage Bin 9A	1,120	79.06	0.02
73	Corn Storage Bin 9B	1,120	79.06	0.02
74	Corn Storage Bin 10A	1,120	79.06	0.02
75	Corn Storage Bin 10B	1,120	79.06	0.02
76	Corn Storage Bin 11A	1,120	79.06	0.02
77	Corn Storage Bin 11B	1,120	79.06	0.02
78	Corn Storage Bin 12A	1,120	79.06	0.02
79	Corn Storage Bin 12B	1,120	79.06	0.02
80	Corn Storage Bin 13A	1,120	79.06	0.02
81	Corn Storage Bin 13B	1,120	79.06	0.02
82	Corn Storage Bin 14A	1,120	79.06	0.02
83	Corn Storage Bin 14B	1,120	79.06	0.02
84	Corn Storage Bin 15A	1,120	79.06	0.02
85	Corn Storage Bin 15B	1,120	79.06	0.02
86	Corn Storage Bin 16A	1,120	79.06	0.02
87	Corn Storage Bin 16B	1,120	79.06	0.02
88	Corn Storage Bin 17A	1,120	79.06	0.02
89	Corn Storage Bin 17B	1,120	79.06	0.02
105	Rail Corn Silo #1	1,120	79.06	0.39
106	Rail Corn Silo #2	1,120	79.06	0.90
COGEN2	Rotary Car Dumper/Truck Dump Building Unit 1	4,000	96.96	0.71
COGEN3	Rotary Car Dumper/Truck Dump Building Unit 2	4,000	96.96	0.71
COGEN4	Coal Storage Dome/Reclaim Tunnel	4,000	96.96	0.68
COGEN5	Crusher Tower	500	68.96	0.51
COGEN6	Powerhouse Bunker Bay	500	68.96	0.55
COGEN7	Fly Ash Transfer/Storage Unit 1	2	6.52	0.24
COGEN8	Fly Ash Transfer/Storage Unit 2	2	6.52	0.24
COGEN9	Bottom Ash Collection Unit 1	0.5	2.58	0.08
COGEN10	Bottom Ash Collection Unit 2	0.5	2.58	0.08
COGEN11	Bottom Ash Transfer/Storage Unit 1	0.5	2.58	0.08
COGEN12	Bottom Ash Transfer/Storage Unit 2	0.5	2.58	0.08
COGEN13	Limestone Storage Unit 1	3	8.56	0.21
COGEN14	Limestone Storage Unit 2	3	8.56	0.21
COGEN15	Limestone Transfer Unit 1	2	6.52	0.21
COGEN16	Limestone Transfer Unit 2	2	6.52	0.21
COGEN17-18	CoGeneration Cooling Towers Unit #1	701	73.08	0.02
COGEN19-22	CoGeneration Cooling Towers Unit #2	8,507	108.81	0.21
SETHA 1-6	Ethanol Cooling Towers (6 cells)	11,259	113.47	4.76
SFRUC 1-3	Fructose Cooling Towers (3 cells)	5,404	101.57	0.21



# Appendix A: Emission Calculations

## Title 129, Chapter 20, Section 002 - PM Limitations for Combustion Sources

Total Heat Input (MMBtu/hr)	Maximum Allowable Emissions of PM (lbs/MMBtu)
10 or less	0.6
Between 10 and 10,000	$1.026/I^{0.233}$ Where I = total heat input in MMBtu/hr.
10,000 or more	0.12

SV #	Process equipment	hp	MMBtu/hr	Allowable PM (lbs/MMBtu)	Unit PM emission rate (lbs/MMBtu)
38	Natural Gas Boiler # 1		145	0.32	0.0075
39	Natural Gas Boiler # 2		240	0.29	0.0075
40	Natural Gas Boiler # 3		180.6	0.31	0.0075
40	Natural Gas Boiler # 4		180.6	0.31	0.0075
98	Natural Gas Boiler # 5		250	0.28	0.0075
COGEN1	COGEN Boilers		1,536	0.19	0.028
16	Gluten Flash Dryer #1		55	0.40	0.32
18	Gluten Flash Dryer #2		65	0.39	0.15
8	Fluidized Bed Germ Dryer #1		55	0.40	0.05
41	Biogas Flare		8	0.60	0.126
109	Emergency Generator SCU	10	0.07	0.60	0.31
99	Emergency Generator - Warehouse 1	68	0.48	0.60	0.31
95	Fire Pump #1	235	1.65	0.60	0.31
96	Fire Pump #2	130	0.91	0.60	0.31
107	Fire Pump #3	375	2.63	0.60	0.31
108	Fire Pump #4	375	2.63	0.60	0.31
90	Ethanol Loadout Flare		2.81	0.60	0.08

To convert hp to MMBtu/hr:  $hp * ((7,000 \text{ Btu/hr})/hp) * (1 \text{ MMBtu}/1,000,000 \text{ Btu})$

Unit PM emission rate = (Unit's lbs/hr PM)/(Unit's MMBtu/hr)

**Appendix A: Emission Calculations**  
**Title 129, Chapter 24 - SO<sub>x</sub> Limitations for Combustion Sources**

Maximum Allowable Emissions of SO<sub>x</sub>: 2.5 lbs/MMBtu

Unit SO<sub>x</sub> emission rate = (Unit's lbs/hr SO<sub>x</sub>)/(Unit's MMBtu/hr)

SV #	Process equipment	hp	MMBtu/hr	Unit SO <sub>x</sub> emission rate (lbs/MMBtu)
38	Natural Gas Boiler #1		145	0.0006
39	Natural Gas Boiler #2		240	0.0006
40	Natural Gas Boiler #3		180.6	0.0006
40	Natural Gas Boiler #4		180.6	0.0006
98	Natural Gas Boiler #5		250	0.0006
COGEN1	COGEN Boilers		1,536	0.11 - 0.20
16	Gluten Flash Dryer #1		55	0.12
18	Gluten Flash Dryer #2		65	0.04
8	Fluidized Bed Germ Dryer #1		55	0.01
35	Carbon Furnace #1		10	0.20
36	Carbon Furnace #2		15.9	0.21
41	Biogas Flare		8	5.00
109	Emergency Generator SCU	10	0.07	0.29
99	Emergency Generator - Warehouse 1	68	0.48	0.29
95	Fire Pump #1	235	1.65	0.29
96	Fire Pump #2	130	0.91	0.29
107	Fire Pump #3	375	2.63	0.29
108	Fire Pump #4	375	2.63	0.29
90	Ethanol Loadout Flare		2.81	0.0008

To convert hp to MMBtu/hr:  $hp * ((7,000 \text{ Btu/hr})/hp) * (1 \text{ MMBtu}/1,000,000 \text{ Btu})$

Unit SO<sub>x</sub> emission rate = (Unit's lbs/hr PM)/(Unit's MMBtu/hr)

**Appendix A: Emission Calculations**  
**Material Handling Fugitives**

Emission Unit ID	Emission Source	Throughput (ton/hr)	Throughput (ton/yr)	PM Emission Factor <sup>a</sup> (lbs/ton)	Uncontrolled PM Emissions (lb/hr)	Uncontrolled PM Emissions (ton/yr)	Capture Efficiency (%)	Controlled PM Emissions (ton/yr)
GRN_FUG	Rail Grain Receiving	1,140	1,248,300	0.032	36.48	20.0	99%	0.20
GRN_FUG	Truck Grain Receiving (Straight)	228	249,660	0.18	41.04	22.5	99%	0.22
GRN_FUG	Truck Grain Receiving (Hopper)	912	998,640	0.035	31.92	17.5	99%	0.17
COAL_FUG	Coal Receiving	2,200	1,050,000	0.02	44.00	10.5	90%	1.05

<sup>a</sup> Emission factor for grain handling is from AP-42, Table 9.9.1-1 (AP-42, 03/03). Emission Factor for Coal handling from FIRE database (SCC 30501008).

PTE annual = throughput (tons/yr) \* emission factor (lbs/ton) \* 1/(2,000 lbs/ton) \* (1 - Capture Efficiency)

Emission Unit ID	Emission Source	Throughput (ton/hr)	Throughput (ton/yr)	PM <sub>10</sub> Emission Factor <sup>a</sup> (lbs/ton)	Uncontrolled PM <sub>10</sub> Emissions (lb/hr)	Uncontrolled PM <sub>10</sub> Emissions (ton/yr)	Capture Efficiency (%)	Controlled PM <sub>10</sub> Emissions (ton/yr)
GRN_FUG	Rail Grain Receiving	1,140	1,248,300	0.0078	8.89	4.9	99%	0.05
GRN_FUG	Truck Grain Receiving (Straight)	228	249,660	0.059	13.45	7.4	99%	0.07
GRN_FUG	Truck Grain Receiving (Hopper)	912	998,640	0.0078	7.11	3.9	99%	0.04
COAL_FUG	Coal Receiving	2,200	1,050,000	0.006	13.20	3.2	90%	0.32

<sup>a</sup> Emission factor for grain handling is from AP-42, Table 9.9.1-1 (AP-42, 03/03). Emission Factor for Coal handling from FIRE database (SCC 30501008).

**Appendix A: Emission Calculations**  
**Process PM and PM<sub>10</sub> Emissions**

**Conditions XIII(A), (C), (D), (E), (L), and (R)**

SV#	Unit Description	Constants	Process Rate (tons/hr)	ACFM	DSCFM	Grain Loading (gr/dscf)	Potential Emissions (lbs/hour)	Potential Emissions (tons/year)
1	Corn Receiving (E)	a	560	12,000	12,187	0.005	0.52	2.29
2	Corn Receiving (W)	a	560	12,000	12,187	0.005	0.52	2.29
3	Corn Cleaner/Fines Bin		45		2,344	0.005	0.10	0.44
4	Corn Cleaner	h	28	20,680	20,370	0.003	0.52	2.29
6	Starch Dryer # 1	e	12.5	93,000	80,701	0.00438	3.03	13.27
9	Germ Cooler # 1	b	5	18,200	17,140	0.005	0.73	3.22
9	Germ Cooler # 2	b	5	19,000	17,893	0.005	0.77	3.36
9	Germ Cooler # 3	b	5	13,300	12,525	0.005	0.54	2.35
12	Germ Cooler # 4	b	15	62,000	58,389	0.0031	1.55	6.80
17	Gluten Cooler # 1		7.5		29,163	0.005	1.25	5.47
19	Gluten Cooler # 2		7.5		36,940	0.005	1.58	6.93
20	Starch Storage Bin # 11	b	12.5	782	736	0.005	0.03	0.14
21	Starch Storage Bin # 12	b	12.5	782	736	0.005	0.03	0.14
22	Starch Storage Bin # 9	b	12.5	782	736	0.005	0.03	0.14
23	Starch Storage Bin # 10	b	12.5	782	736	0.005	0.03	0.14
24	Gluten Storage Bin # 7	b	22	782	736	0.005	0.03	0.14
25	Gluten Storage Bin # 8	b	22	782	736	0.005	0.03	0.14
26	Gluten Storage Bin # 5	b	22	782	736	0.005	0.03	0.14
27	Gluten Storage Bin # 6	b	22	782	736	0.005	0.03	0.14
28	Germ Storage Bin # 3	b	15	782	736	0.005	0.03	0.14
29	Germ Storage Bin # 4	b	15	782	736	0.005	0.03	0.14
30	Germ Storage Bin # 1	b	15	782	736	0.005	0.03	0.14
31	Germ Storage Bin # 2	b	15	782	736	0.005	0.03	0.14
42	Corn Fines Transfer	a	42	1,000	1,016	0.005	0.04	0.19
43	Fiber Dewatering		22		7,344	0.01	0.63	2.76
44	Gluten Recycle	h	7	2,500	2,463	0.005	0.11	0.46
45	Starch Dryer #2	e	12.5	93,000	80,701	0.00438	3.03	13.27
46	Starch Bin #13	c	13	1,500	1,430	0.005	0.06	0.27
47	Starch Bin #14	c	13	1,500	1,430	0.005	0.06	0.27
48	Starch Dryer Loadout	d	2	2,800	2,531	0.005	0.11	0.48
54	Corn Silo #1		1,120		369	0.005	0.02	0.07
55	Corn Silo #2		1,120		369	0.005	0.02	0.07
56	Corn Silo #3		1,120		369	0.005	0.02	0.07
57	Corn Silo #4		1,120		493	0.005	0.02	0.09
58	Corn Silo #5		1,120		493	0.005	0.02	0.09
59	Corn Silo #6		1,120		493	0.005	0.02	0.09
60	Corn Silo #7		1,120		493	0.005	0.02	0.09
61	Corn Silo #8		1,120		493	0.005	0.02	0.09
62	Lime Silo Bin	h	30	1,500	1,478	0.01	0.13	0.55
63	Soda Ash Receiving		30		495	0.02	0.08	0.37
71	Rail Corn Storage and Handling	h	14	32,500	32,013	0.003	0.82	3.61
72	Corn Storage Bin 9A	h	1,120	417	411	0.005	0.02	0.08
73	Corn Storage Bin 9B	h	1,120	417	411	0.005	0.02	0.08
74	Corn Storage Bin 10A	h	1,120	417	411	0.005	0.02	0.08
75	Corn Storage Bin 10B	h	1,120	417	411	0.005	0.02	0.08
76	Corn Storage Bin 11A	h	1,120	417	411	0.005	0.02	0.08
77	Corn Storage Bin 11B	h	1,120	417	411	0.005	0.02	0.08
78	Corn Storage Bin 12A	h	1,120	417	411	0.005	0.02	0.08
79	Corn Storage Bin 12B	h	1,120	417	411	0.005	0.02	0.08
80	Corn Storage Bin 13A	h	1,120	417	411	0.005	0.02	0.08
81	Corn Storage Bin 13B	h	1,120	417	411	0.005	0.02	0.08
82	Corn Storage Bin 14A	h	1,120	417	411	0.005	0.02	0.08
83	Corn Storage Bin 14B	h	1,120	417	411	0.005	0.02	0.08
84	Corn Storage Bin 15A	h	1,120	417	411	0.005	0.02	0.08
85	Corn Storage Bin 15B	h	1,120	417	411	0.005	0.02	0.08
86	Corn Storage Bin 16A	h	1,120	417	411	0.005	0.02	0.08
87	Corn Storage Bin 16B	h	1,120	417	411	0.005	0.02	0.08
88	Corn Storage Bin 17A	h	1,120	417	411	0.005	0.02	0.08
89	Corn Storage Bin 17B	h	1,120	417	411	0.005	0.02	0.08
105	Rail Corn Silo #1		1,120		15,000	0.003	0.39	1.69
106	Rail Corn Silo #2		1,120		35,000	0.003	0.90	3.94
COGEN2	Rotary Car Dumper/Truck Dump Building Unit 1		4,000		16,500	0.005	0.71	3.10
COGEN3	Rotary Car Dumper/Truck Dump Building Unit 2		4,000		16,500	0.005	0.71	3.10
COGEN4	Coal Storage Dome/Reclaim Tunnel		4,000		15,760	0.005	0.68	2.96
COGEN5	Crusher Tower		500		11,820	0.005	0.51	2.22
COGEN6	Powerhouse Bunker Bay		500		12,805	0.005	0.55	2.40
COGEN7	Fly Ash Transfer/Storage Unit 1		2.0		5,572	0.005	0.24	1.05
COGEN8	Fly Ash Transfer/Storage Unit 2		2.0		5,572	0.005	0.24	1.05
COGEN9	Bottom Ash Collection Unit 1		0.5		1,857	0.005	0.08	0.35
COGEN10	Bottom Ash Collection Unit 2		0.5		1,857	0.005	0.08	0.35
COGEN11	Bottom Ash Transfer/Storage Unit 1		0.5		1,857	0.005	0.08	0.35
COGEN12	Bottom Ash Transfer/Storage Unit 2		0.5		1,857	0.005	0.08	0.35
COGEN13	Limestone Storage Unit 1		3.0		4,925	0.005	0.21	0.92
COGEN14	Limestone Storage Unit 2		3.0		4,925	0.005	0.21	0.92
COGEN15	Limestone Transfer Unit 1		2.0		4,925	0.005	0.21	0.92
COGEN16	Limestone Transfer Unit 2		2.0		4,925	0.005	0.21	0.92
<b>Totals</b>							23.12	101.24

**Constants**

Temp (F)	Constants	Moisture %	Grains/lb	Minute/hr
50	a	0.019	7,000	60
90	b	0.019	7,000	60
90	c	0.007	7,000	60
120	d	0.007	7,000	60
115	e	0.055	7,000	60
170	f	0.15	7,000	60
50	g	0.1	7,000	60
68	h	0.015	7,000	60

**Methodology**

DSCFM=Exhaust Rate (ACFM) x (68 + 460)/(Temp +460) X (1 - Moisture%)

PM/PM<sub>10</sub> (lb/hr) = Exhaust Rate (dscfm) x Grain Loading Limit(gr/dscf) x (60 min/hr) x (1 lb/7,000 grains)

PM/PM<sub>10</sub> (tons/year) = lb/hr x (8,760 hours/1 Year) x (1 ton/2,000 lbs)

**Appendix A: Emission Calculations****Conditions XIII.(B) and (C)****Millhouse/Feedhouse (SV# 5), Fiber Dewatering (SV #43), Stillage/Steepwater Evaporators (SV 69/70), Gluten RVF's (SV 66/67/68)**

SV#	Unit Description	Process Rate	PM Emission Factor	PM <sub>10</sub> Emission Factor	SO <sub>2</sub> Emission Factor	VOC Emission Factor	Potential Annual Emissions PM	Potential Annual Emissions PM <sub>10</sub>	Potential Annual Emissions SO <sub>2</sub>	Potential Annual Emissions VOC
		(tons/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(tons/yr)	(tons/yr)	(tons/yr)	(tons/yr)
66	Gluten RVF (SE) <sup>a</sup>				0.04	0.2			0.18	0.88
67	Gluten RVF (SW) <sup>a</sup>				0.04	0.2			0.18	0.88
68	Gluten RVF (NW) <sup>a</sup>				0.02	0.1			0.09	0.44
69	Stillage/Steepwater Evaporator (E) <sup>a</sup>				9.3	48.8			40.73	213.74
70	Stillage/Steepwater Evaporator (W) <sup>a</sup>				11.1	47.5			48.62	208.05
5	Millhouse/Feedhouse <sup>a</sup>	280	3.89	3.89	6.75	4.84	17.04	17.04	29.57	21.20
43	Fiber Dewatering <sup>b</sup>	22			4.06	1.52			17.78	6.66

<sup>a</sup> PM, PM<sub>10</sub>, and SO<sub>2</sub> emission factors based on applicant estimate, to be verified through stack testing. VOC estimate based on the consent-decree required 95% control level for this scrubber, applied to uncontrolled emission estimates (based on engineering calculations) for the three Gluten RVF Vents (SV 66-68) and the two Stillage MR Vents (SV 69 and 70). The scrubber controls other processes at the millhouse/feedhouse. However, emissions from those units are currently unknown. The millhouse scrubber is subject to a 95% (or 20 ppmvd) VOC emission limit per the consent decree, but does not have a (lb/hr) VOC emission limitation.

<sup>b</sup> SO<sub>2</sub> and VOC emission factors based on applicant estimate, to be verified through stack testing.

**Methodology**

Potential To Emit (tons/yr) = Emission Factor (lb/hr) x (8,760 hr/yr) x (1 ton/2,000 lbs)

**Appendix A: Emission Calculations****Conditions XIII.(D) and (E)****Germ Dryers #1-3 (SV# 7), Germ Coolers #1-4 (SV#s 9-12), Gluten Cooler and Recycle (SV#s 17, 19, and 44)**

SV #	Unit Description	Process Rate	PM Emission Factor <sup>a</sup>	PM <sub>10</sub> Emission Factor <sup>a</sup>	SO <sub>2</sub> Emission Factor <sup>a</sup>	VOC Emission Factor <sup>a</sup>	Potential Annual Emissions PM	Potential Annual Emissions PM <sub>10</sub>	Potential Annual Emissions SO <sub>2</sub>	Potential Annual Emissions VOC
		(tons/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(tons/yr)	(tons/yr)	(tons/yr)	(tons/yr)
7	Germ Dryer # 1	4.5	7.81	3.82	8.50	23.00	34.21	16.73	37.23	100.74
7	Germ Dryer # 2	4.5								
7	Germ Dryer # 3	2.8								
9	Germ Cooler # 1 <sup>b</sup>	5				1.80				7.88
10	Germ Cooler # 2 <sup>b</sup>	5				1.90				8.32
11	Germ Cooler # 3 <sup>b</sup>	5				1.40				6.13
12	Germ Cooler # 4 <sup>b</sup>	15				6.50				28.47
17	Gluten Cooler # 1 <sup>b</sup>	7.5				2.08				9.11
19	Gluten Cooler # 2 <sup>b</sup>	7.5				2.62				11.48
44	Gluten Recycle <sup>b</sup>					0.20				0.88

<sup>a</sup> Emission factors based on source tests.<sup>b</sup> PM/PM<sub>10</sub> emissions for SV's 9-12, 17, 19, and 44 are on the Process PM and PM<sub>10</sub> emissions worksheet.**Methodology**

Potential to Emit (tons/yr) = Limited Emission Factor (lb Pollutant/hr) x (8,760 hr/yr) x (1 ton/2,000 lbs)

**Appendix A: Emission Calculations****Condition XIII.(D)****Combustion Emissions from Gluten Flash Dryer # 1 (SV-16)****Gluten Flash Dryer #1, with Low NO<sub>x</sub> burner and wet contact scrubber**Heat Input Capacity  
MMBtu/hrPotential Throughput  
MMCF/yr

55.0

472.35

Pollutant	CAS #	Emission Factor (lbs/MMscf)	Potential Hourly Emissions (lbs/hr)	Potential Annual Emissions (tons/yr)
PM			17.51	76.7
PM <sub>10</sub>			8.00	35.04
NO <sub>x</sub>			4.35	19.05
SO <sub>2</sub>			6.60	28.91
CO			15.20	66.58
VOC			22.80	99.86
Individual HAPs				
Arsenic Compounds		0.0002	1.08E-05	4.72E-05
Benzene	71432	0.0021	1.13E-04	4.96E-04
Beryllium Compounds		0.000012	6.47E-07	2.83E-06
Cadmium Compounds		0.0011	5.93E-05	2.60E-04
Chromium Compounds		0.0014	7.55E-05	3.31E-04
Cobalt Compounds		0.000084	4.53E-06	1.98E-05
Dichlorobenzene	25321226	0.0012	6.47E-05	2.83E-04
Formaldehyde	50000	0.075	4.04E-03	1.77E-02
n-Hexane	10543	1.8	9.71E-02	4.25E-01
Lead Compounds		0.0005	2.70E-05	1.18E-04
Manganese Compounds		0.00038	2.05E-05	8.97E-05
Mercury Compounds		0.00026	1.40E-05	6.14E-05
Naphthalene	91203	0.00061	3.29E-05	1.44E-04
Nickel Compounds		0.0021	1.13E-04	4.96E-04
Polycyclic Organic Matter		0.0000882	4.76E-06	2.08E-05
Selenium Compounds		0.000024	1.29E-06	5.67E-06
Toluene	108883	0.0034	1.83E-04	8.03E-04
Total HAPs			0.1018	0.4460

The HAP emission factors are from AP-42 (7/1998), Tables 1.4-2, 1.4-3 and 1.4-4. Criteria emission factors are based on applicant estimate and stack testing data for CO and VOC (process and combustion emissions). This unit has a PM limit from ADM's 1995 PSD permit that includes filterable particulate only (3.34 lb/hr). The PM emission factor used here, which includes filterable particulate, was developed by multiplying the PM<sub>10</sub> limit by the ratio of PM to PM<sub>10</sub> limits on Gluten Flash Dryer #2.

**Methodology**

All emission factors are based on normal firing.

MMBtu = 1,000,000 Btu

MMCF = 1,000,000 Cubic Feet of Gas

Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,000 MMBtu

Potential Annual Criteria Emissions (tons/year) = Hourly emission rate (lb/hr) x (8,760 hr/yr) x (1 ton/2,000)

Potential Annual HAP Emissions (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

**Appendix A: Emission Calculations****Condition XIII.(D)****Combustion Emissions from Gluten Flash Dryer #2 (SV-18)****Gluten Flash Dryer #2, with Low NO<sub>x</sub> burner and wet contact scrubber**Heat Input Capacity  
MMBtu/hrPotential Throughput  
MMCF/yr  
558.24

65.0

Pollutant	CAS #	Emission Factor (lbs/MMscf)	Potential Hourly Emissions (lbs/hr)	Potential Annual Emissions (tons/yr)
PM			9.85	43.14
PM <sub>10</sub>			4.50	19.71
NO <sub>x</sub>			3.90	17.08
SO <sub>2</sub>			2.40	10.51
CO			4.74	20.76
VOC			22.20	97.24
Individual HAPs				
Arsenic Compounds		0.0002	1.08E-05	4.72E-05
Benzene	71432	0.0021	1.13E-04	4.96E-04
Beryllium Compounds		0.000012	6.47E-07	2.83E-06
Cadmium Compounds		0.0011	5.93E-05	2.60E-04
Chromium Compounds		0.0014	7.55E-05	3.31E-04
Cobalt Compounds		0.000084	4.53E-06	1.98E-05
Dichlorobenzene	25321226	0.0012	6.47E-05	2.83E-04
Formaldehyde	50000	0.075	4.04E-03	1.77E-02
n-Hexane	10543	1.8	9.71E-02	4.25E-01
Lead Compounds		0.0005	2.70E-05	1.18E-04
Manganese Compounds		0.00038	2.05E-05	8.97E-05
Mercury Compounds		0.00026	1.40E-05	6.14E-05
Naphthalene	91203	0.00061	3.29E-05	1.44E-04
Nickel Compounds		0.0021	1.13E-04	4.96E-04
Polycyclic Organic Matter		0.0000882	4.76E-06	2.08E-05
Selenium Compounds		0.000024	1.29E-06	5.67E-06
Toluene	108883	0.0034	1.83E-04	8.03E-04
Total HAPs			0.1018	0.4460

The HAP emission factors are from AP-42 (7/1998), Tables 1.4-2, 1.4-3 and 1.4-4. Criteria emission factors are based on applicant estimate and stack testing data for CO and VOC (process and combustion emissions).

**Methodology**

All emission factors are based on normal firing.

MMBtu = 1,000,000 Btu

MMCF = 1,000,000 Cubic Feet of Gas

Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,000 MMBtu

Potential Annual Criteria Emissions (tons/year) = Hourly emission rate (lb/hr) x (8,760 hr/yr) x (1 ton/2,000)

Potential Annual HAP Emissions (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton



**Appendix A: Emission Calculations**
**Condition XIII.(D)**
**Combustion Emissions from the Fluidized Bed Germ Dryer #1 (SV# 8)**
**Fluidized Bed Germ Dryer #1 (SV# 8), with Low NO<sub>x</sub> burner and cyclone/wet contact scrubber**

Heat Input Capacity

Potential Throughput

MMBtu/hr

MMCF/yr

55.0

472.35

Pollutant	CAS #	Emission Factor	Potential Hourly Emissions (lbs/hr)	Potential Annual Emissions (tons/yr)
PM			3.00	13.14
PM <sub>10</sub>			3.00	13.14
NO <sub>x</sub>			3.30	14.45
SO <sub>2</sub>			0.51	2.23
CO			4.02	17.61
VOC			1.50	6.57
Individual HAPs		(lbs/MMscf)		
Arsenic Compounds		0.0002	1.08E-05	4.72E-05
Benzene	71432	0.0021	1.13E-04	4.96E-04
Beryllium Compounds		0.000012	6.47E-07	2.83E-06
Cadmium Compounds		0.0011	5.93E-05	2.60E-04
Chromium Compounds		0.0014	7.55E-05	3.31E-04
Cobalt Compounds		0.000084	4.53E-06	1.98E-05
Dichlorobenzene	25321226	0.0012	6.47E-05	2.83E-04
Formaldehyde	50000	0.075	4.04E-03	1.77E-02
n-Hexane	10543	1.8	9.71E-02	4.25E-01
Lead Compounds		0.0005	2.70E-05	1.18E-04
Manganese Compounds		0.00038	2.05E-05	8.97E-05
Mercury Compounds		0.00026	1.40E-05	6.14E-05
Naphthalene	91203	0.00061	3.29E-05	1.44E-04
Nickel Compounds		0.0021	1.13E-04	4.96E-04
Polycyclic Organic Matter		0.0000882	4.76E-06	2.08E-05
Selenium Compounds		0.000024	1.29E-06	5.67E-06
Toluene	108883	0.0034	1.83E-04	8.03E-04
Total HAPs			0.1018	0.4460

The HAP emission factors are from AP-42 (7/1998), Tables 1.4-2, 1.4-3 and 1.4-4. Criteria emission factors are based on applicant estimate and will be verified through stack testing.

**Methodology**

All emission factors are based on normal firing.

MMBtu = 1,000,000 Btu

MMCF = 1,000,000 Cubic Feet of Gas

Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu

Potential Annual Criteria Emissions (tons/year) = Hourly emission rate (lb/hr) x (8,760 hr/yr) x (1 ton/2,000)

Potential Annual HAP Emissions (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

**Appendix A: Emission Calculations****Condition XIII.(F)****Fermentation and Distillation (SV# 32, 33, and 34)**

SV #	Unit Description	SO <sub>2</sub> Emission Factor <sup>a</sup>	VOC Emission Factor <sup>a</sup>	Potential Annual Emissions SO <sub>2</sub>	Potential Annual Emissions VOC
		(lb/hr)	(lb/hr)	(tons/yr)	(tons/yr)
32,33,34	Fermenters, Distillation Scrubbers	2.50	13.50	10.95	59.13

<sup>a</sup> Emission factors based on applicant estimate, to be verified through stack testing.

**Methodology**

Potential to Emit (tons/yr) = Emission Factor (lb/hr) x (8,760 hr/yr) x (1 ton/2,000 lbs)

**Appendix A: Emission Calculations**  
**Storage Tanks**

**Condition XIII.(G)**

SV #	Unit Description	Capacity (gallons)	Potential VOC Emissions <sup>a</sup> (lbs/yr)	Potential VOC Emissions (tons/yr)
TK-01	Day Tank A - Ethanol	100,000	666.47	0.33
TK-02	Day Tank B - Ethanol	100,000	666.47	0.33
TK-03	Rerun Tank - Ethanol	34,000	220.67	0.11
TK-04	Day Tank C - Ethanol	100,000	1,037.51	0.52
TK-05	Denaturant Tank	42,000	1,650.86	0.83
TK-06	Denatured Ethanol Tank	2,284,000	1,586.08	0.79
TK-07	Corrosion Inhibitor Tank	3,800	9.77	0.005
TK-08	Denaturant Tank	105,000	2,200.00	1.10

<sup>a</sup> Emissions based on TANKS 4.09b program.

	CAS #	HAP Emission Summary (lbs/yr) <sup>a</sup>								Total
		TK-01	TK-02	TK-03	TK-04	TK-05	TK-06	TK-07	TK-08	
Acetaldehyde	75070	4.62	4.62	3.00	4.99		15.92			33.15
Benzene	71432					7.53	1.92		10.03	19.48
Cumene	98828					0.35	0.10		0.47	0.92
Ethyl benzene	100414					1.21	0.34		1.61	3.16
n-Hexane	10543					6.61	1.61		8.81	17.03
Methanol	67561	0.98	0.98	0.44	1.35		2.49	5.90		12.14
Toluene	108883					10.78	2.94		14.37	28.09
1,2,4- Trimethyl benzene	120821					1.51	0.41		2.01	3.93
2,2,4- Trimethyl pentane	540841					8.62	2.60		11.49	22.71
Xylenes	1330207					5.66	1.57	0.09	7.54	14.86

<sup>a</sup> Emissions based on TANKS 4.09b program.

## Appendix A: Emission Calculations

Condition XIII.(H)

### Liquid Product Loadout (truck and rail loadout controlled) (SV #90)

Anhydrous ethanol loading rate:	120 MMgal/yr	
Denaturant loading rate:	6 MMgal/yr	
Denatured ethanol loading rate:	126 MMgal/yr	
S <sub>normal dedicated</sub>	0.6	
S <sub>clean cargo</sub>	0.5	
	Rail	Truck
Capture efficiency:	100.0%	100.0%
Control efficiency:	95.0%	95.0%
Overall control efficiency:	95.0%	95.0%

VOC emission factor equation from AP-42, Section 5.2.2 - Loading Losses (1/1995):

$$\text{VOC} = 12.46 * S * P * M / T * (1 - \text{eff} / 100) * X = \text{lbs/Mgal per component}$$

Physical Data	Materials		
	Gasoline	Ethanol	Denaturant
Vapor molecular weight (M)	62	46	62
Temperature (T, deg R) <sup>a</sup>	510	525	525
Vapor pressure (P, psia) <sup>b</sup>	5.96	0.77	7.57
Liquid molecular weight (ML)	92	46	92
Density (lb/gal)	5.6	6.6	5.6
Liquid Mole Fraction	NA	0.98	0.02

<sup>a</sup> T<sub>gasoline</sub> is annual average ambient temperature from Tank 4.0 for Norfolk, NE.

Denatured ethanol is loaded out at elevated temperature.

<sup>b</sup> Assume worst-case based on RVP 13 gasoline.

VOC Emissions (tpy)	E <sub>VOC</sub> , uncontrolled (Truck)	E <sub>VOC</sub> , uncontrolled (Rail)	E <sub>VOC</sub> , controlled (100% Truck)	E <sub>VOC</sub> , controlled (100% Rail)
E <sub>gasoline</sub>	56.88	NA	2.84	NA
E <sub>ethanol</sub>	25.93	31.12	1.30	1.56
E <sub>denaturant</sub>	7.29	8.75	0.36	0.44
Total	90.09	39.86	4.50	1.99

**Appendix A: Emission Calculations**  
**Liquid Product Loadout HAPs**

**Condition XIII.(H)**

VOC Emissions (tpy)	E <sub>VOC</sub> , uncontrolled (Truck)	E <sub>VOC</sub> , uncontrolled (Rail)	E <sub>VOC</sub> , controlled (100% Truck)	E <sub>VOC</sub> , controlled (100% Rail)
E <sub>gasoline</sub>	56.88	NA	2.84	NA
E <sub>ethanol</sub>	25.93	31.12	1.30	1.56
E <sub>denaturant</sub>	7.29	8.75	0.36	0.44

HAP	CAS #	Emission Factor (Wt Fraction of VOC Emissions) *		
		Gasoline	Ethanol	Denaturant
Benzene	71432	2.50E-03	-	2.50E-03
Carbon Disulfide	75150	2.00E-05	-	2.00E-05
Cumene	98828	1.00E-04	-	1.00E-04
Ethyl benzene	100414	5.00E-05	-	5.00E-05
n-Hexane	10543	5.00E-02	-	5.00E-02
Toluene	108883	5.00E-03	-	5.00E-03
Xylene	1330207	5.00E-04	-	5.00E-04
Acetaldehyde	75070	-	2.00E-04	-
Methanol	67561	-	2.00E-04	-

\* Speciation profiles as provided by applicant.

HAP	CAS #	Controlled Emissions - Truck (tpy)			
		Gasoline	Ethanol	Denaturant	Total
Acetaldehyde	75070	-	2.59E-04	-	2.59E-04
Benzene	71432	7.11E-03	-	9.11E-04	8.02E-03
Carbon Disulfide	75150	5.69E-05	-	7.29E-06	6.42E-05
Cumene	98828	2.84E-04	-	3.64E-05	3.21E-04
Ethyl benzene	100414	1.42E-04	-	1.82E-05	1.60E-04
n-Hexane	10543	1.42E-01	-	1.82E-02	1.60E-01
Methanol	67561	-	2.59E-04	-	2.59E-04
Toluene	108883	1.42E-02	-	1.82E-03	1.60E-02
Xylene	1330207	1.42E-03	-	1.82E-04	1.60E-03
Total HAP					1.87E-01

HAP	CAS #	Controlled Emissions - Rail (tpy)			
		Gasoline	Ethanol	Denaturant	Total
Acetaldehyde	75070	-	3.11E-04	-	3.11E-04
Benzene	71432	-	-	1.09E-03	1.09E-03
Carbon Disulfide	75150	-	-	8.75E-06	8.75E-06
Cumene	98828	-	-	4.37E-05	4.37E-05
Ethyl benzene	100414	-	-	2.19E-05	2.19E-05
n-Hexane	10543	-	-	2.19E-02	2.19E-02
Methanol	67561	-	3.11E-04	-	3.11E-04
Toluene	108883	-	-	2.19E-03	2.19E-03
Xylene	1330207	-	-	2.19E-04	2.19E-04
Total HAP					2.61E-02

HAP	CAS #	Controlled Emissions - Worst-case truck or rail (tpy)		
		Truck Emissions	Rail Emissions	Total
Acetaldehyde	75070	2.59E-04	3.11E-04	3.11E-04
Benzene	71432	8.02E-03	1.09E-03	8.02E-03
Carbon Disulfide	75150	6.42E-05	8.75E-06	6.42E-05
Cumene	98828	3.21E-04	4.37E-05	3.21E-04
Ethyl benzene	100414	1.60E-04	2.19E-05	1.60E-04
n-Hexane	10543	1.60E-01	2.19E-02	1.60E-01
Methanol	67561	2.59E-04	3.11E-04	3.11E-04
Toluene	108883	1.60E-02	2.19E-03	1.60E-02
Xylene	1330207	1.60E-03	2.19E-04	1.60E-03
Total HAP		1.87E-01	2.61E-02	1.87E-01

HAP Emissions = E<sub>VOC</sub> \* (Wt Fraction of VOC emissions)

**Appendix A: Emission Calculations**  
**Liquid Product Loadout Flare (SV# 90)**

**Condition XIII.(H)**

Parameter	Value	Units	Basis / Source
Anydrous Ethanol (200 proof) Production	=	120,000,000 gal/yr	
Denatured Ethanol Production	=	126,000,000 gal/yr	Assumes 1.05 gal. of Completely Denatured Alcohol (CDA or Fuel Alcohol) per 1.0 gal. of 200 proof anhydrous ethanol.
Heating Value	=	197.0 Btu/gal	Value for Denatured Ethanol Vapor (Manufacturer's Data)
Capture Efficiency	=	100% wt. %	Design Specification
Control Efficiency	=	95% wt. %	Design Specification
Maximum Loading Rate	=	113,000 gal/hr	Design Specification - Max rating for flare
Weighted Average density of vapors	=	5.89 lbs/gal	
MMBtu from vapors	=	5.725 MMBtu/yr	
	=	0.005 MMBtu/hr	(based on 161.60 lbs/hr VOC from truck loadout, uncontrolled - 113,000 gal/hr loading rate)
Maximum Supplemental Fuel Required	=	45.0 scfm	Manufacturer's Data
Pilot Gas Rate	=	54.0 scf/hr	Manufacturer's Data
Heating value of natural gas	=	1,020.0 MMBtu/MMscf	
Total natural gas usage	=	2,754 scf/hr	
	=	0.003 MMscf/hr =	2.809 MMBtu/hr
	=	24.125 MMscf/yr =	24,607.541 MMBtu/yr
Flare PM and PM <sub>10</sub> Emission Factor	=	0.03 lb/MMBtu	AP-42; 9/91; Table 13.5-1 (estimated value for lightly smoking flares using f-factor of 10,610 scf/MMBtu)
	=		(40 ug/L)*(g/1,000,000 ug)*(lbs/454 g)*(28.317 L/scf)*(10,610 scf/MMBtu) = lbs/MMBtu
Flare NO <sub>x</sub> Emission Factor	=	2.00 mg/L	Manufacturer's Specification (equiv. to .15 lb/mmbtu)
	=	1.67E-05 lbs/gal	Conversion by: (mg/L)*(3.7854 L/gal)*(2.2046 x 10 <sup>6</sup> lbs/mg) = lbs/gal
Flare CO Emission Factor	=	5.00 mg/L	Manufacturer's Specification (equiv. to .35 lb/mmbtu)
	=	4.17E-05 lbs/gal	Conversion by: (mg/L)*(3.7854 L/gal)*(2.2046 x 10 <sup>6</sup> lbs/mg) = lbs/gal
Flare SO <sub>2</sub> Emission Factor	=	0.60 lb/MMScf	AP-42; 7/98; Table 1.4-2 (EF for natural gas)

Pollutant	Emission Factor	Hourly Process Rate	Annual Process Rate	Potential Hourly Emissions (lbs/hr)	Potential Annual Emissions (tons/yr)
PM	0.03 lbs/MMBtu	2.814 MMBtu/hr	24,613.266 MMBtu/yr	0.08	0.37
PM <sub>10</sub>	0.03 lbs/MMBtu	2.814 MMBtu/hr	24,613.266 MMBtu/yr	0.08	0.37
NO <sub>x</sub>	1.67E-05 lbs/gal	113,000 gal/hr	126,000,000 gal/yr	1.89	1.05
SO <sub>2</sub>	0.6 lbs/MMscf	0.003 MMscf/hr	24.125 MMscf/yr	0.002	0.0072
CO	4.17E-05 lbs/gal	113,000 gal/hr	126,000,000 gal/yr	4.71	2.63
Individual HAPs	CAS#				
Arsenic Compounds		0.0002 lbs/MMscf		5.51E-07	2.41E-06
Benzene	71432	0.0021 lbs/MMscf		5.78E-06	2.53E-05
Beryllium Compounds		0.000012 lbs/MMscf		3.30E-08	1.45E-07
Cadmium Compounds		0.0011 lbs/MMscf		3.03E-06	1.33E-05
Chromium Compounds		0.0014 lbs/MMscf		3.86E-06	1.69E-05
Cobalt Compounds		0.000084 lbs/MMscf		2.31E-07	1.01E-06
Dichlorobenzene	25321226	0.0012 lbs/MMscf		3.30E-06	1.45E-05
Formaldehyde	50000	0.075 lbs/MMscf		2.07E-04	9.05E-04
n-Hexane	10543	1.8 lbs/MMscf		4.96E-03	2.17E-02
Lead Compounds		0.0005 lbs/MMscf		1.38E-06	6.03E-06
Manganese Compounds		0.00038 lbs/MMscf		1.05E-06	4.58E-06
Mercury Compounds		0.00026 lbs/MMscf		7.16E-07	3.14E-06
Naphthalene	91203	0.00061 lbs/MMscf		1.68E-06	7.36E-06
Nickel Compounds		0.0021 lbs/MMscf		5.78E-06	2.53E-05
Polycyclic Organic Matter		0.0000882 lbs/MMscf		2.43E-07	1.06E-06
Selenium Compounds		0.000024 lbs/MMscf		6.61E-08	2.90E-07
Toluene	108883	0.0034 lbs/MMscf		9.36E-06	4.10E-05
Total HAPs				0.0052	0.0228

**NOTE:**

Calculation assumes that 100% of potential fuel alcohol production is loaded into non-dedicated trucks or rail cars which are controlled by the flare. This is a worst-case scenario for a secondary emissions perspective (i.e., flare combustion emissions are maximized).

**Appendix A: Emission Calculations**
**Condition XIII.(I)**
**Carbon Furnace No. 1 (SV# 35) and Carbon Furnace No. 2 (SV# 36)**

Pollutant	Carbon Furnace #1 (SV-35)			Carbon Furnace #2 (SV-36)		
	Process Rate	Emission Factor	Potential Annual Emissions	Process Rate	Emission Factor	Potential Annual Emissions
	(tons/hr)	(lbs/hr) <sup>a</sup>	(tons/yr)	(tons/hr)	(lbs/hr) <sup>a</sup>	(tons/yr)
PM	0.9375	1.88	8.23	1.5625	3.14	13.75
PM <sub>10</sub>		1.00	4.38		1.50	6.57
NO <sub>x</sub>		3.38	14.80		5.64	24.70
SO <sub>2</sub>		2.00	8.76		3.30	14.45
CO		7.63	33.42		8.14	35.65
VOC		2.70	11.83		3.80	16.64

<sup>a</sup> Emission Factors based on stack testing (multiple tests between 8/01 and 5/02).

**Criteria Pollutant Methodology**

Potential to Emit (tons/yr) = Emission Factor (lb/hr) x (8,760 hr/yr) x (1 ton/2,000 lbs)

Total Furnace design rate:	25.9 MMBtu/hr (Furnace #1 10 MMBtu/hr, Furnace #2 15.9 MMBtu/hr)
Operating hours:	8,760 hrs/yr
Heat content:	1,020 MMBtu/MMscf
Potential throughput:	0.025 MMscf/hr
Potential throughput:	219.000 MMscf/yr

Furnaces - Natural Gas Combustion HAP Emissions				
Pollutant	CAS #	Emission Factor (lbs/MMscf)	Potential Hourly Emissions (lbs/hr)	Potential Annual Emissions (tons/yr)
Arsenic Compounds		0.0002	5.00E-06	2.19E-05
Benzene	71432	0.0021	5.25E-05	2.30E-04
Beryllium Compounds		0.000012	3.00E-07	1.31E-06
Cadmium Compounds		0.0011	2.75E-05	1.20E-04
Chromium Compounds		0.0014	3.50E-05	1.53E-04
Cobalt Compounds		0.000084	2.10E-06	9.20E-06
Dichlorobenzene	25321226	0.0012	3.00E-05	1.31E-04
Formaldehyde	50000	0.075	1.88E-03	8.21E-03
Lead Compounds		0.0005	1.25E-05	5.48E-05
Manganese Compounds		0.00038	9.50E-06	4.16E-05
Mercury Compounds		0.00026	6.50E-06	2.85E-05
Naphthalene		0.00061	1.53E-05	6.68E-05
n-Hexane	10543	1.8	4.50E-02	1.97E-01
Nickel Compounds		0.0021	5.25E-05	2.30E-04
Polycyclic Organic Matter		0.0000882	2.21E-06	9.66E-06
Selenium Compounds		0.000024	6.00E-07	2.63E-06
Toluene	108883	0.0034	8.50E-05	3.72E-04
Total HAPs			4.72E-02	2.07E-01

For units under 100 MMBtu/hr, and uncontrolled. The emission factors are from AP-42 (7/1998), Tables 1.4-3 and 1.4-4.

**HAP Methodology**

Controlled Hourly PTE = (hourly throughput rate)(emission factor) = lbs/hr

Controlled Annual PTE = (annual throughput rate)(emission factor)/(2,000 lbs/ton) = tons/yr

**Appendix A: Emission Calculations**
**Condition XIII.(J)**
**Criteria Pollutant from Natural Gas Boilers 1-4 (SV# 38, 39, and 40)**

	NO <sub>x</sub> <sup>a</sup>			
	Boiler 1	Boiler 2	Boiler 3	Boiler 4
Heat Input Capacity (MMBtu/hr)	145	240	180.6	180.6
Emission Factor in lb/MMBtu	0.06	0.074	0.074	0.074
Potential Emission in lbs/hr	8.70	17.76	13.36	13.36
Potential Emission in tons/yr	38.11	77.79	58.54	58.54

<sup>a</sup> NO<sub>x</sub> Emission Factors based on applicant estimate and will be verified through stack testing.

Heat Input Capacity MMBtu/hr	Potential Throughput MMscf/yr
746.2	6,408.54

(4 units total)

Pollutant		Emission Factor (lbs/MMscf)	Potential Hourly Emissions (lbs/hr)	Potential Annual Emissions (tons/yr)
PM		7.6	5.56	24.35
PM <sub>10</sub>		7.6	5.56	24.35
SO <sub>2</sub>		0.6	0.44	1.92
CO		84	61.45	269.16
VOC		5.5	4.02	17.62
Individual HAPs	CAS #			
Arsenic Compounds		0.0002	1.46E-04	6.41E-04
Benzene	71432	0.0021	1.54E-03	6.73E-03
Beryllium Compounds		0.000012	8.78E-06	3.85E-05
Cadmium Compounds		0.0011	8.05E-04	3.52E-03
Chromium Compounds		0.0014	1.02E-03	4.49E-03
Cobalt Compounds		0.000084	6.15E-05	2.69E-04
Dichlorobenzene	25321226	0.0012	8.78E-04	3.85E-03
Formaldehyde	50000	0.075	5.49E-02	2.40E-01
n-Hexane	110543	1.8	1.32E+00	5.77E+00
Lead Compounds		0.0005	3.66E-04	1.60E-03
Manganese Compounds		0.00038	2.78E-04	1.22E-03
Mercury Compounds		0.00026	1.90E-04	8.33E-04
Napthalene	91203	0.00061	4.46E-04	1.95E-03
Nickel Compounds		0.0021	1.54E-03	6.73E-03
Polycyclic Organic Matter		0.0000882	6.45E-05	2.83E-04
Selenium Compounds		0.000024	1.76E-05	7.69E-05
Toluene	108883	0.0034	2.49E-03	1.09E-02
Total HAPs			1.3815	6.0511

The emission factors are from AP-42 (7/1998), Tables 1.4-1, 1.4-2, 1.4-3 and 1.4-4.

**Methodology**

All emission factors are based on normal firing.

MMBtu = 1,000,000 Btu

MMCF = 1,000,000 Cubic Feet of Gas

Potential Throughput (MMscf) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMscf/1,020 MMBtu

Potential to Emit NO<sub>x</sub> (tons/year) = Heat Input Capacity (MMBtu/hr) x NO<sub>x</sub> Emission Factor (lb/MMBtu) x (8,760 hr/yr) x (

Potential to Emit Other Pollutants (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/(2,000 lb/ton)



**Appendix A: Emission Calculations**  
**Criteria Pollutant and HAP Emissions**

**Condition XIII.(J)**

**From one (1) 250 MMBtu/hr Natural Gas Fired Boiler (Boiler 5, SV #98)**

Heat Input Capacity

MMBtu/hr

250.0

Potential Throughput

MMscf/yr

2,147.06

Pollutant		Emission Factor (lbs/MMscf)	Potential Hourly Emissions (lbs/hr)	Potential Annual Emissions (tons/yr)
PM		7.6	1.86	8.16
PM <sub>10</sub>		7.6	1.86	8.16
NO <sub>x</sub>		36.72	9.00	39.42
SO <sub>2</sub>		0.6	0.15	0.64
CO		96.288	23.60	103.37
VOC		5.5	1.35	5.90
Individual HAPs	CAS #			
Arsenic Compounds		0.0002	4.90E-05	2.15E-04
Benzene	71432	0.0021	5.15E-04	2.25E-03
Beryllium Compounds		0.000012	2.94E-06	1.29E-05
Cadmium Compounds		0.0011	2.70E-04	1.18E-03
Chromium Compounds		0.0014	3.43E-04	1.50E-03
Cobalt Compounds		0.000084	2.06E-05	9.02E-05
Dichlorobenzene	25321226	0.0012	2.94E-04	1.29E-03
Formaldehyde	50000	0.075	1.84E-02	8.05E-02
n-Hexane	110543	1.8	4.41E-01	1.93E+00
Lead Compounds		0.0005	1.23E-04	5.37E-04
Manganese Compounds		0.00038	9.31E-05	4.08E-04
Mercury Compounds		0.00026	6.37E-05	2.79E-04
Napthalene	91203	0.00061	1.50E-04	6.55E-04
Nickel Compounds		0.0021	5.15E-04	2.25E-03
Polycyclic Organic Matter		0.0000882	2.16E-05	9.47E-05
Selenium Compounds		0.000024	5.88E-06	2.58E-05
Toluene	108883	0.0034	8.33E-04	3.65E-03
Total HAPs			0.4629	2.0273

The emission factors are from AP-42 (7/1998), Tables 1.4-1, 1.4-2, 1.4-3 and 1.4-4. CO and NO<sub>x</sub> emission factors are based on a permit application and will be verified through stack testing.

**Methodology**

All emission factors are based on normal firing.

MMBtu = 1,000,000 Btu

MMCF = 1,000,000 Cubic Feet of Gas

Potential Throughput (MMscf) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMscf/1,020 MMBtu

Potential to Emit NO<sub>x</sub> (tons/year) = Heat Input Capacity (MMBtu/hr) x NO<sub>x</sub> Emission Factor (lb/MMBtu) x (8,760 hr/yr) x (1 ton/2,000 lbs)

Potential to Emit Other Pollutants (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/(2,000 lb/ton)

**Appendix A: Emission Calculations**  
**Criteria Pollutant and HAP Emissions**  
**From two (2) 768 MMBtu/hr Coal Fired Boilers (SV COGEN1)**

**Condition XIII.(K)**

Max. Heat Input Rate MMBtu/hr	
1,536	(2 units combined)
Tons of coal:	90.35 tons/hr 791,466.00 tons/yr

Heating Value of Coal  
17 MMBtu/ton  
(@ 8,500 btu/lb)

Pollutant	CAS #	Emission Factor (lbs/MMBtu) <sup>a</sup>	Potential Emissions (lbs/hr)	Potential Emissions (tons/yr)
PM		0.0275	42.24	185.01
PM <sub>10</sub>		0.025	38.40	168.19
NO <sub>x</sub>		0.07	107.52	470.94
SO <sub>2</sub> <sup>b</sup>		0.2	307.20	1,345.54
CO		0.1	153.60	672.77
VOC		0.007	10.75	47.09
Hydrochloric acid (HCl)	7647010	0.02	30.72	134.55
Hydrofluoric acid (HF)	7664393	0.0012	1.84	8.07
Lead Compounds (Pb)		0.0002	0.31	1.35
Mercury Compounds (Hg)		0.000003	0.004608	0.020
Sulfuric Acid (H <sub>2</sub> SO <sub>4</sub> )		0.01	15.36	67.28
		(lbs/ton coal) <sup>c</sup>		
2,4-Dinitrotoluene	121142	2.80E-07	2.53E-05	1.11E-04
2-Chloroacetophenone	532274	7.00E-06	6.32E-04	2.77E-03
Acetaldehyde	75070	5.70E-04	5.15E-02	2.26E-01
Acetophenone	98862	1.50E-05	1.36E-03	5.94E-03
Acrolein	107028	2.90E-04	2.62E-02	1.15E-01
Antimony Compounds		1.80E-05	1.63E-03	7.12E-03
Arsenic Compounds		4.10E-04	3.70E-02	1.62E-01
Benzene	71432	1.30E-03	1.17E-01	5.14E-01
Benzyl chloride	100447	7.00E-04	6.32E-02	2.77E-01
Beryllium Compounds		2.10E-05	1.90E-03	8.31E-03
Bis(2-ethylhexyl)phthalate	117817	7.30E-05	6.60E-03	2.89E-02
Bromoform	75252	3.90E-05	3.52E-03	1.54E-02
Cadmium Compounds		5.10E-05	4.61E-03	2.02E-02
Carbon disulfide	75150	1.30E-04	1.17E-02	5.14E-02
Chlorobenzene	108907	2.20E-05	1.99E-03	8.71E-03
Chloroform	67663	5.90E-05	5.33E-03	2.33E-02
Chromium Compounds		2.60E-04	2.35E-02	1.03E-01
Cobalt Compounds		1.00E-04	9.04E-03	3.96E-02
Cumene	98828	5.30E-06	4.79E-04	2.10E-03
Cyanide Compounds		2.50E-03	2.26E-01	9.89E-01
Dimethyl sulfate	77781	4.80E-05	4.34E-03	1.90E-02
Ethyl benzene	100414	9.40E-05	8.49E-03	3.72E-02
Ethyl chloride	75003	4.20E-05	3.79E-03	1.66E-02
Ethylene dibromide	106934	1.20E-06	1.08E-04	4.75E-04
Ethylene dichloride	107062	4.00E-04	3.61E-02	1.58E-01
Formaldehyde	50000	2.40E-04	2.17E-02	9.50E-02
Hexane	110543	6.70E-05	6.05E-03	2.65E-02
Isophorone	78591	5.80E-04	5.24E-02	2.30E-01
Manganese Compounds		4.90E-04	4.43E-02	1.94E-01
Methyl bromide	74839	1.60E-04	1.45E-02	6.33E-02
Methyl chloride	74873	5.30E-04	4.79E-02	2.10E-01
Methyl chloroform	71556	2.00E-05	1.81E-03	7.91E-03
Methyl ethyl ketone	78933	3.90E-04	3.52E-02	1.54E-01
Methyl hydrazine	60344	1.70E-04	1.54E-02	6.73E-02
Methyl methacrylate	80626	2.00E-05	1.81E-03	7.91E-03
Methyl tert butyl ether	1634044	3.50E-05	3.16E-03	1.39E-02
Methylene chloride	75092	2.90E-04	2.62E-02	1.15E-01
Naphthalene	91203	1.30E-05	1.17E-03	5.14E-03
Nickel Compounds		2.80E-04	2.53E-02	1.11E-01
Phenol	108952	1.60E-05	1.45E-03	6.33E-03
Polycyclic Organic Matter		7.76E-06	7.01E-04	3.07E-03
Propionaldehyde	123386	3.80E-04	3.43E-02	1.50E-01
Selenium Compounds		1.30E-03	1.17E-01	5.14E-01
Styrene	100425	2.50E-05	2.26E-03	9.89E-03
Tetrachloroethylene	127184	4.30E-05	3.89E-03	1.70E-02
Toluene	108883	2.40E-04	2.17E-02	9.50E-02
Vinyl Acetate	108054	7.60E-06	6.87E-04	3.01E-03
Xylenes	1330207	3.70E-05	3.34E-03	1.46E-02
Total HAPs			18.6441	148.9381

PM emission factor includes BACT limit of  
0.015 lb/MMBtu (filterable) + 50% of PM10 emission factor  
expected to account for condensable fraction of total PM  
0.015 + (0.025 \* 50%) = 0.0275 total PM

<sup>a</sup> The emission factors are in lbs/MMBtu based on proposed PSD-BACT and HAP-MACT limits (HCl and Hg).

<sup>b</sup> SO<sub>2</sub> limit varies from 0.11 to 0.2 lb/MMBtu depending on fuel sulfur input.

<sup>c</sup> Emission factors from AP-42 Tables 1.1-13, 1.1-14, and 1.1-18.

**Methodology**

Potential Emissions (lbs/hr) = Max. Heat Input Rate (MMBtu/hr) x Emission Factor (lbs/MMBtu)

Potential Emissions (tons/yr) = lbs/hr x (8,760 hr/yr) x (1 ton/2,000 lbs)

## Appendix A: Emission Calculations

## Condition XIII.(M)

### Cooling Towers (EU13-E1-E6, EU13-F1-F3, EU9-17-18, EU9-19-22)

#### Assumptions:

Tower Type:

Induced Draft with Drift Eliminator Control Technology

	EU13-E1-E6	EU13-F1-F3	EU9-17-18	EU9-19-22	
Total Dissolved Solids:	2,500	2,500	2,500	2,500	ppm
Liquid Drift Loss:	0.008	0.008	0.0005	0.0005	%
Number of Cells	6	3	2	4	cells
Individual Cell Flow Rate	9,000	7,200	1,400	8,500	gpm
Cooling Water Flow:	45,000	21,600	2,800	34,000	gpm total
Operation Hours:	8,760	8,760	8,760	8,760	hrs/yr

According to AP-42<sup>1</sup>, "a conservatively high PM<sub>10</sub> emission factor can be obtained by...multiplying the total liquid drift factor by the total dissolved solids (TDS) fraction in the circulating water..." In a technical article entitled "*Calculating Realistic PM<sub>10</sub> Emissions from Cooling Towers*"<sup>2</sup>, the authors use the AP-42 guidance to express the total particulate emissions (PM), after the pure water has evaporated as:

Equation 1:  $PM_{cell} \text{ (lb/hr)} = \text{Water Circulation Rate (gal/hr)} \times 8.34 \text{ (lb/gal)} \times \text{Drift Rate (\%)} \times \text{TDS (ppm)} \times 60 \text{ (min/hr)}$

Equation 2:  $PM_{total} \text{ (lb/hr)} = PM_{cell} \times \text{(Number of cells)}$

	EU13-E1-E6	EU13-F1-F3	EU9-17-18	EU9-19-22	
$PM_{cell}$	0.90	0.72	0.01	0.05	lb/hr
$PM_{total}$	5.40	2.16	0.02	0.21	lb/hr
$PM_{cell}$	3.95	3.16	0.04	0.23	tpy
$PM_{total}$	23.67	9.47	0.08	0.93	tpy

To calculate the fraction of the PM that is actually PM<sub>10</sub>, the authors considered the impact of TDS concentration on the actual particle size generation. Using the methodology put forth in this technical article, the maximum potential PM<sub>10</sub> emissions from the process cooling towers at the Columbus facility are calculated by interpolating the EPRI % Mass Smaller in the table below to determine a value for PM<sub>10</sub>.

Therefore, the percent PM<sub>10</sub> fraction for a TDS value of 2,200 ppm, as interpolated from the table below, is 60.16% ((49.812 + 70.509)/2) of the total PM.

#### Supporting Calculations for Estimated PM<sub>10</sub> Emission for 2500 ppm TDS Water

EPRI Droplet Diameter (um)	Droplet Volume (um <sup>3</sup> )	Droplet, Mass (ug)	Particle Mass (Solids) (ug)	Solid Particle Volume (um <sup>3</sup> )	Intermediate Value	Solid Particle Diameter (um)	EPRI % Mass Smaller
10	524	5.24E-04	1.15E-06	5.24E-01	5.00E-01	1.00E+00	0
20	4,189	4.19E-03	9.22E-06	4.19E+00	1.00E+00	2.00E+00	0.196
30	14,137	1.41E-02	3.11E-05	1.41E+01	1.50E+00	3.00E+00	0.226
40	33,510	3.35E-02	7.37E-05	3.35E+01	2.00E+00	4.00E+00	0.514
50	65,450	6.55E-02	1.44E-04	6.55E+01	2.50E+00	5.00E+00	1.806
60	113,097	1.13E-01	2.49E-04	1.13E+02	3.00E+00	6.00E+00	5.702
70	179,594	1.80E-01	3.95E-04	1.80E+02	3.50E+00	7.00E+00	21.348
<b>90</b>	<b>381,704</b>	<b>3.82E-01</b>	<b>8.40E-04</b>	<b>3.82E+02</b>	<b>4.50E+00</b>	<b>9.00E+00</b>	<b>49.812</b>
<b>110</b>	<b>696,910</b>	<b>6.97E-01</b>	<b>1.53E-03</b>	<b>6.97E+02</b>	<b>5.50E+00</b>	<b>1.10E+01</b>	<b>70.509</b>
130	1,150,347	1.15E+00	2.53E-03	1.15E+03	6.50E+00	1.30E+01	82.023
150	1,767,146	1.77E+00	3.89E-03	1.77E+03	7.50E+00	1.50E+01	88.012
180	3,053,628	3.05E+00	6.72E-03	3.05E+03	9.00E+00	1.80E+01	91.032
210	4,849,048	4.85E+00	1.07E-02	4.85E+03	1.05E+01	2.10E+01	92.468
240	7,238,229	7.24E+00	1.59E-02	7.24E+03	1.20E+01	2.40E+01	94.091
270	10,305,995	1.03E+01	2.27E-02	1.03E+04	1.35E+01	2.70E+01	94.689
300	14,137,167	1.41E+01	3.11E-02	1.41E+04	1.50E+01	3.00E+01	96.288
350	22,449,298	2.24E+01	4.94E-02	2.24E+04	1.75E+01	3.50E+01	97.011
400	33,510,322	3.35E+01	7.37E-02	3.35E+04	2.00E+01	4.00E+01	98.34
450	47,712,938	4.77E+01	1.05E-01	4.77E+04	2.25E+01	4.50E+01	99.071
500	65,449,847	6.54E+01	1.44E-01	6.54E+04	2.50E+01	5.00E+01	99.071
600	113,097,336	1.13E+02	2.49E-01	1.13E+05	3.00E+01	6.00E+01	100

**Appendix A: Emission Calculations**
**Condition XIII.(M)**
**Cooling Towers (EU13-E1-E6, EU13-F1-F3, EU9-17-18, EU9-19-22)**

The PM<sub>10</sub> emissions from the cooling towers were calculated using the PM values calculated from Eq. 1 multiplies by the percent PM<sub>10</sub> calculated for the TDS water in the cooling towers. Therefore, for the 2,200 ppm TDS water in the cooling towers, the calculated PM<sub>10</sub> is:

	<b>PM<sub>10</sub> Fraction</b>	<b>EU13-E1-E6</b>	<b>EU13-F1-F3</b>	<b>EU9-17-18</b>	<b>EU9-19-22</b>	
PM <sub>10(CELL)</sub>	60.16%	0.54	0.43	0.01	0.03	lb/hr
PM <sub>10(TOTAL)</sub>	60.16%	3.25	1.30	0.01	0.13	lb/hr
PM <sub>10(CELL)</sub>	60.16%	2.37	1.90	0.02	0.14	tpy
PM <sub>10(TOTAL)</sub>	60.16%	14.24	5.70	0.05	0.56	tpy

Equation 1: PM<sub>10(CELL)</sub> (lb/hr) = Water Circulation Rate (gal/hr) x 8.34 (lb/gal) x Drift Rate (%) x TDS (ppm) x 60.16% x 60 (min/hr)

Equation 2: PM<sub>10(TOTAL)</sub> (lb/hr) = PM<sub>10(CELL)</sub> x (Number of cells)

	<b>Summary Potential Emissions</b>				
	<b>PM Emissions</b>		<b>PM<sub>10</sub> Emissions</b>		
	<b>(lb/hr)</b>	<b>(tpy)</b>	<b>(lb/hr)</b>	<b>(tpy)</b>	<b>(g/sec)</b>
EU13-E1-E6 1 cell	<b>0.79</b>	<b>3.46</b>	<b>0.54</b>	<b>2.37</b>	<b>0.068</b>
EU13-E1-E6 6 cells	<b>4.76</b>	<b>20.85</b>	<b>3.25</b>	<b>14.24</b>	
EU13-F1-F3 1 cell	<b>0.63</b>	<b>2.78</b>	<b>0.43</b>	<b>1.90</b>	<b>0.054</b>
EU13-F1-F3 3 cells	<b>1.90</b>	<b>8.33</b>	<b>1.30</b>	<b>5.70</b>	
EU9-17-18 1 cell	<b>0.01</b>	<b>0.04</b>	<b>0.01</b>	<b>0.02</b>	<b>0.001</b>
EU9-17-18 2 cells	<b>0.02</b>	<b>0.08</b>	<b>0.01</b>	<b>0.05</b>	
EU9-19-22 1 cell	<b>0.05</b>	<b>0.23</b>	<b>0.03</b>	<b>0.14</b>	<b>0.004</b>
EU9-19-22 4 cells	<b>0.21</b>	<b>0.93</b>	<b>0.13</b>	<b>0.56</b>	

<sup>1</sup> USEPA, AP-42, Fifth Edition (1995), Volume I, Chapter 13: Miscellaneous Sources, Part 13.4, Wet Cooling Towers, page 13.4-3

<sup>2</sup> PM/PM<sub>10</sub> fraction calculated by interpolation of data provided in "Calculating Realistic PM<sub>10</sub> Emissions from Cooling Towers", Joel Reisman and Gordon Frisbie, Abstract No. 216, presented at the 2001 Air & Waste Management Association 94th Annual Conference and Exhibition in Orlando, FL, June 25-28.

**Appendix A: Emission Calculations**  
**Equipment Leaks (EQ\_LKS\_FUG)**

**Condition XIII.(N)**

Parameter	Value	Units	Basis
<b>Vogelbusch Area Components</b>			
Pumps =	12 sources		FEMs Database and Field Audit
Compressors =	0 sources		FEMs Database and Field Audit
Valves =	461 sources		FEMs Database and Field Audit
Connectors =	1,275 sources		FEMs Database and Field Audit (includes flanges)
Pressure Relief Valves =	20 sources		FEMs Database and Field Audit
<b>Delta T Area Components</b>			
Pumps =	12 sources		FEMs Database and Field Audit
Compressors =	0 sources		FEMs Database and Field Audit
Valves =	231 sources		FEMs Database and Field Audit
Connectors =	572 sources		FEMs Database and Field Audit (includes flanges)
Pressure Relief Valves =	7 sources		FEMs Database and Field Audit
<b>Tank Farm Area Components</b>			
Pumps =	10 sources		FEMs Database and Field Audit
Compressors =	0 sources		FEMs Database and Field Audit
Valves =	220 sources		FEMs Database and Field Audit
Connectors =	690 sources		FEMs Database and Field Audit (includes flanges)
Pressure Relief Valves =	0 sources		FEMs Database and Field Audit
<b>Pre-Evap Area Components</b>			
Pumps =	1 sources		FEMs Database and Field Audit
Compressors =	1 sources		FEMs Database and Field Audit
Valves =	94 sources		FEMs Database and Field Audit
Connectors =	80 sources		FEMs Database and Field Audit (includes flanges)
Pressure Relief Valves =	0 sources		FEMs Database and Field Audit
<b>Fermentation Area Components</b>			
Pumps =	4 sources		FEMs Database and Field Audit
Compressors =	0 sources		FEMs Database and Field Audit
Valves =	99 sources		FEMs Database and Field Audit
Connectors =	74 sources		FEMs Database and Field Audit (includes flanges)
Pressure Relief Valves =	7 sources		FEMs Database and Field Audit
<b>Total Source Components</b>			
<i>Number of leaks documented from 10/03 through 9/04 monitoring period</i>			
Pumps =	39 sources		1
Compressors =	1 sources		0
Valves =	1,105 sources		25
Connectors =	2,691 sources		20
Pressure Relief Valves =	34 sources		1
Total =	3,870 sources		47
<b>LDAR Data</b>			
Pumps>10K =	0.21% % of sources		Obtained from facility LDAR monitoring records (10/03 to 9/04)
Compressors>10K =	0.00% % of sources		Installed 9/04
Valves>10K =	0.19% % of sources		Obtained from facility LDAR monitoring records (10/03 to 9/04)
Connectors>10K =	0.06% % of sources		Obtained from facility LDAR monitoring records (10/03 to 9/04)
Pressure Relief Valves =	0.25% % of sources		Obtained from facility LDAR monitoring records (10/03 to 9/04)
<b>VOC Emissions Factors</b>			
Pumps>10K =	0.243000 kg/hr/source		Protocol for Equipment Leak Emission Estimates; Table 2-5; light liquid service; 1995.
Compressors>10K =	1.608000 kg/hr/source		Protocol for Equipment Leak Emission Estimates; Table 2-5; gas service; 1995.
Valves>10K =	0.078200 kg/hr/source		Protocol for Equipment Leak Emission Estimates; Table 2-5; gas service; 1995.
Connectors>10K =	0.113000 kg/hr/source		Protocol for Equipment Leak Emission Estimates; Table 2-5; all service; 1995.
Pressure Relief Valves >10K =	1.691000 kg/hr/source		Protocol for Equipment Leak Emission Estimates; Table 2-5; light liquid service; 1995.
Pumps<10K =	0.001870 kg/hr/source		Protocol for Equipment Leak Emission Estimates; Table 2-5; light liquid service; 1995.
Compressors<10K =	0.089400 kg/hr/source		Protocol for Equipment Leak Emission Estimates; Table 2-5; gas service; 1995.
Valves<10K =	0.000131 kg/hr/source		Protocol for Equipment Leak Emission Estimates; Table 2-5; gas service; 1995.
Connectors<10K =	0.000081 kg/hr/source		Protocol for Equipment Leak Emission Estimates; Table 2-5; all service; 1995.
Pressure Relief Valves <10K =	0.044700 kg/hr/source		Protocol for Equipment Leak Emission Estimates; Table 2-5; light liquid service; 1995.
Pumps Average =	0.002385 kg/hr/source		Weighted average emission factor for all pumps.
Compressors Average =	0.089400 kg/hr/source		Weighted average emission factor for all compressors.
Valves Average =	0.000278 kg/hr/source		Weighted average emission factor for all valves.
Connectors Average =	0.000151 kg/hr/source		Weighted average emission factor for all connectors.
Pressure Relief Valves =	0.048735 kg/hr/source		Weighted average emission factor for all pressure relief valves.
<b>VOC Emission Rates</b>			
Pumps =	0.90 tpy		(number of components) * average emission factor * 2.2 (kg/lb) * (ton/2,000 lbs) * 8,760 (hr/yr)
Compressors =	0.86 tpy		(number of components) * average emission factor * 2.2 (kg/lb) * (ton/2,000 lbs) * 8,760 (hr/yr)
Valves =	2.96 tpy		(number of components) * average emission factor * 2.2 (kg/lb) * (ton/2,000 lbs) * 8,760 (hr/yr)
Connectors =	3.91 tpy		(number of components) * average emission factor * 2.2 (kg/lb) * (ton/2,000 lbs) * 8,760 (hr/yr)
Pressure Relief Valves =	15.97 tpy		(number of components) * average emission factor * 2.2 (kg/lb) * (ton/2,000 lbs) * 8,760 (hr/yr)
<b>Total =</b>	<b>24.60 tpy</b>		

Road Description	Travel Distance	Potential Rate	Paved PM EF <sup>a</sup>	Paved PM <sub>10</sub> EF <sup>a</sup>	Potential PM Emissions	Potential PM <sub>10</sub> Emissions
	(miles)	(trucks/yr)	(lb/VMT)	(lb/VMT)	(tons/yr)	(tons/yr)
Grain Transportation	0.96	155,125	0.31	0.06	22.74	4.43
Starch	1.08	365	0.31	0.06	0.06	0.01
Germ	1.08	5,475	0.31	0.06	0.90	0.18
Gluten	1.08	365	0.31	0.06	0.06	0.01
Feed	0.24	27,375	0.31	0.06	1.00	0.20
Ethanol	1.08	2,190	0.31	0.06	0.36	0.07
By-Product	0.89	12,045	0.31	0.06	1.64	0.32
Chem Deliveries - Route 1	0.89	730	0.31	0.06	0.10	0.02
Chem Deliveries - Route 2	1.08	1,095	0.31	0.06	0.18	0.04
Chem Deliveries - Route 3	0.62	365	0.31	0.06	0.03	0.01
Chem Deliveries - Route 4	0.57	365	0.31	0.06	0.03	0.01
Fructose	1.13	4,745	0.31	0.06	0.82	0.16
CoGen Ash	1.51	5,840	0.31	0.06	1.35	0.26
CoGen Lime	1.51	1,460	0.31	0.06	0.34	0.07
CoGen Coal	1.54	16,425	0.31	0.06	3.86	0.75
<b>Total:</b>					33.5	6.5

#### Methodology

Potential to Emit (tons/yr) = Travel Distance (miles) x Number of Trucks/yr x Paved EF (lb/VMT) \* (ton/2,000 lb)

<sup>a</sup> Paved road emission factor calculated using the paved road equation in AP-42, Section 13.2.1 (12/03 Version), with an adjustment factor of (1/9.1) applied to reflect ADM testing data at their Columbus, NE and Marshall, MN corn wet mills:

$$Lbs/VMT = \left[ k \left( \frac{sL}{2} \right)^{0.65} \left( \frac{W}{3} \right)^{1.5} - C \right] \left( 1 - \frac{P}{4N} \right) (1/9.1)$$

Where:

Constants	Value	Units
Average Truck Weight (W)	27.5	tons
Rainy Days (P)	90	days/yr
Days in Period (N)	365	days/yr
Paved Road Silt Loading (sL)	3	g/m2
Paved PM particle size factor (k)	0.082	lb/VMT
Paved PM <sub>10</sub> particle size factor (k)	0.016	lb/VMT
Brake wear emission factor (C)	0.00047	lb/VMT

**Appendix A: Emission Calculations**
**Condition XIII.(P)**
**Emergency Equipment Emissions from Distillate Oil Combustion**

Emergency Generator - SCU	SV 99	10 HP
Emergency Generator - Warehouse 1	SV 99	68 HP
Fire Pump #1	SV 95	235 HP
Fire Pump #2	SV 96	130 HP
Fire Pump #3	SV 107	375 HP
Fire Pump #4	SV 108	375 HP

Hours/yr	Horsepower (HP)	Heating Value (Btu/hp-hr)	Heat Input MMBtu/hr	Heat Input MMBtu/yr
400	1,193	7,000	8.35	3340.40

Criteria Pollutants		Emission Factor <sup>a</sup> (lb/MMBtu)	Pollutant Emissions		
			lb/hr	lb/yr	TPY
Particulate Matter (PM)		0.31	2.59	1,035.52	0.52
Particulate Matter < 10 Microns (PM <sub>10</sub> )		0.31	2.59	1,035.52	0.52
Nitrogen Oxides (NO <sub>x</sub> )		4.41	36.83	14,731.16	7.37
Sulfur Oxides (SO <sub>x</sub> )		0.29	2.42	968.72	0.48
Carbon Monoxide (CO)		0.95	7.93	3,173.38	1.59
Volatile Organic Compounds (VOC)		0.36	3.01	1,202.54	0.60

Hazardous Air Pollutants	CAS#	Emission Factor <sup>b</sup> (lb/MMBtu)	Pollutant Emissions		
			lb/hr	lb/yr	TPY
Acetaldehyde	75-07-0	7.67E-04	6.41E-03	2.5621	1.28E-03
Acrolein	107-02-8	9.25E-05	7.72E-04	0.3090	1.54E-04
Benzene	71-43-2	9.33E-04	7.79E-03	3.1166	1.56E-03
1,3-Butadiene	106-99-0	3.91E-05	3.27E-04	0.1306	6.53E-05
Formaldehyde	50-00-0	1.18E-03	9.85E-03	3.9417	1.97E-03
Naphthalene	91-20-3	8.48E-05	7.08E-04	0.2833	1.42E-04
Polycyclic Organic Matter (POM)	-	1.68E-04	1.40E-03	0.5612	2.81E-04
Toluene	108-88-3	4.09E-04	3.42E-03	1.3662	6.83E-04
Xylene	1330-20-7	2.85E-04	2.38E-03	0.9520	4.76E-04
Total HAPs					0.0066

**Notes:**
<sup>a</sup> Emission factors from AP-42 (10/96), Table 3.3-1.

<sup>b</sup> Emission factors from AP-42 (10/96), Table 3.3-2.

**Appendix A: Emission Calculations**  
**Anaerobic Digester Biogas Flare Criteria Pollutant emissions (SV# 41)**

**Condition XIII.(Q)**

Heat Input Capacity  
MMBtu/hr

Potential Throughput  
MMCF/yr

8.0

21.9 (limited to 2,190 hours per year)

Pollutant		Emission Factor (lbs/MMscf)	Potential Hourly Emissions (lbs/hr)	Potential Annual Emissions (tons/yr)
PM		7.6	0.06	0.08
PM <sub>10</sub>		7.6	0.06	0.08
NO <sub>x</sub>		100	0.78	1.10
SO <sub>2</sub>		5,100.09	40.00	55.85
CO		84	0.66	0.92
VOC		5.5	0.04	0.06
Individual HAPs	CAS #			
Arsenic Compounds		0.0002	1.57E-06	2.19E-06
Benzene	71432	0.0021	1.65E-05	2.30E-05
Beryllium Compounds		0.000012	9.41E-08	1.31E-07
Cadmium Compounds		0.0011	8.63E-06	1.20E-05
Chromium Compounds		0.0014	1.10E-05	1.53E-05
Cobalt Compounds		0.000084	6.59E-07	9.20E-07
Dichlorobenzene	25321226	0.0012	9.41E-06	1.31E-05
Formaldehyde	50000	0.075	5.88E-04	8.21E-04
n-Hexane	110543	1.8	1.41E-02	1.97E-02
Lead Compounds		0.0005	3.92E-06	5.48E-06
Manganese Compounds		0.00038	2.98E-06	4.16E-06
Mercury Compounds		0.00026	2.04E-06	2.85E-06
Naphthalene	91203	0.00061	4.78E-06	6.68E-06
Nickel Compounds		0.0021	1.65E-05	2.30E-05
Polycyclic Organic Matter		0.0000882	6.92E-07	9.66E-07
Selenium Compounds		0.000024	1.88E-07	2.63E-07
Toluene	108883	0.0034	2.67E-05	3.72E-05
Total HAPs			0.0148	0.0207

The emission factors are from AP-42 (7/1998), Tables 1.4-1, 1.4-2, 1.4-3 and 1.4-4. SO<sub>2</sub> emission factor based on testing of the H<sub>2</sub>S concentration in the biogas, assuming 100% conversion to SO<sub>2</sub>.

**Methodology**

Assume biogas emissions similar to natural gas emissions (except SO<sub>2</sub> as noted above).

All emission factors are based on normal firing.

Heating value: 800 Btu/scf (biogas)

MMBtu = 1,000,000 Btu

MMCF = 1,000,000 Cubic Feet of Gas

Potential Throughput (MMscf) = Heat Input Capacity (MMBtu/hr) x 2,190 hrs/yr x 1 MMscf/800 MMBtu

Potential to Emit (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/(2,000 lb/ton)

**Biogas Flare Pilot Burner**

Design rate of pilot: 0.1 MMBtu/hr

Heating value: 1,020 Btu/scf (natural gas)

Operating hours: 8,760 hrs/yr

Natural gas combustion AP-42 emission factors came from AP-42, Section 1.4 (7/1998), Tables 1.4-1 and 1.4-2.

Hourly Emissions = (Emission factor lbs/MMBtu)(MMBtu/hr)

Annual Emissions = (Emission factor lbs/MMBtu)(MMBtu/hr)(hrs/yr)/(2,000 lbs/ton)

Pilot Emission Summary			
Pollutant	Emission Factor (lbs/MMBtu)	Hourly Emissions (lbs/hr)	Annual PTE (tons/yr)
PM <sub>10</sub>	0.0076	0.00076	0.003
PM	0.0076	0.00076	0.003
SO <sub>2</sub>	0.0006	0.00006	0.0003
NO <sub>x</sub>	0.1	0.01	0.044
CO	0.084	0.0084	0.037
VOC	0.0055	0.00055	0.002



**Appendix A: Emission Calculations****Condition XIII.(Q)****Wet Feed Pile (WETFEED\_FUG) and Wastewater Treatment (WWTP\_TNKS and WWTP\_FUG)**

Unit	PM/PM <sub>10</sub> (lb/hr)	SO <sub>2</sub> (lb/hr)	VOC (lb/day)	PM/PM <sub>10</sub> (tons/yr)	SO <sub>2</sub> (tons/yr)	VOC (tons/yr)
Wet Feed Pile <sup>a</sup>	0.011	0.95	8.65 (lb/hr)	0.05	4.16	37.89
Equalization Tanks <sup>b</sup>			15.2			2.77
Wastewater Treatment Fugitives <sup>b</sup>			3.9			0.71

<sup>a</sup> SO<sub>2</sub> and VOC emissions based engineering calculations in application, PM/PM<sub>10</sub> based on AP-42 Section 13.2.3.4.

<sup>b</sup> Emissions based on WATER 9 calculations.

**Methodology**

Potential to Emit (tons/yr) = Emission Factor (lb/hr) x (8,760 hr/yr) x (1 ton/2,000 lbs)

Potential to Emit (tons/yr) = Emission Factor (lb/day) x (365 days/yr) x (1 ton/2,000 lbs)

**Appendix A: Emission Calculations**  
**HCl Storage Tank Scrubber (SV# 91)**

**Condition XIII.(R)**

**Assumptions:**

6.9 million pounds of HCl used per year  
HCl is received as 35% solution  
Emissions assume displaced volume contains HCl vapors in equilibrium with solution  
Vapors leaving tank are scrubbed at 99.9% control  
Outside Unloading Tanks: Assume 35% HCl in vapor space

Partial Pressure 35% HCl @ 25°C =	mmHg (interpolated from Perry's Chemical Engineer's Handbook, 7th Edition, table 2-10)
Mole Fraction = $105.25 / (760 * 14.1/14.7) =$	0.14

**Displacement Volume**

Annual Usage /yr =	6,896,381 lbs HCl/yr
Density of water =	8.34 lbs/gal
Specific gravity of 35% HCl =	1.18
Density of 35% HCl =	Density of water * Specific gravity of 35% HCl
Density of 35% HCl =	9.82 lb/gal
Displaced Volume of HCl =	$(6,896,381 \text{ lbs HCl}) * (\text{gal} / 9.823686 \text{ lbs}) * (\text{ft}^3 / 7.48 \text{ gal})$
Displaced Volume of HCl =	98,852 ft <sup>3</sup> /yr

**Pounds of HCL out stack**

Total moles =  $93,852 \text{ ft}^3/\text{yr} / (359 * 537/492) \text{ lb moles/ft}^3 = 239.59 \text{ lb moles}$   
Lb moles HCl =  $239.59 \text{ lb moles} * 0.14438 = 34.58 \text{ lb moles HCl}$   
Lbs HCl =  $34.58 * 36.5 \text{ lbs HCl/lb mole} = 1262.25 \text{ lb/yr}$

Ceilcote Air Pollution Control HCl Scrubber (Model # SPT-12-120) has a design efficiency of 99.9%

Therefore the total amount of HCl emitted to the atmosphere:

$$1262.25 \text{ lb/yr} * 0.001 = 1.26 \text{ lb/yr}$$

**Appendix A: Emission Calculations**  
**Steepwater and Process Waste Tanks**

SV #	Unit	SO <sub>2</sub> (lb/hr/vent) <sup>a</sup>	VOC Emissions (lb/hr/vent) <sup>a</sup>	SO <sub>2</sub> (tons/yr) <sup>a</sup>	VOC Emissions (tons/yr) <sup>a</sup>
92-94	Heavy Steepwater Tanks	0.076	0.17	0.16	0.70
100-102	Process Waste Tanks #1-3		0.79 (lb/hr)		3.48
103	Light Steepwater Tank		0.604 (lb/hr)		2.65
104	Sterile Steepwater Tank		1.26 (lb/hr)		5.52

<sup>a</sup> Estimates based on engineering calculations in application.

## **Appendix B - PSD-BACT and HAP-BACT Analysis for Ethanol Plant Expansion**

This Section presents the Best Available Control Technology (BACT) analysis for the new and modified emissions sources at the Columbus plant including the alcohol plant, the new gas-fired package boiler, and the modified gluten and germ dryers. BACT analyses are provided for all PSD pollutants for which the modifications are significant<sup>1</sup> as well as for HAP as required by N.A.C. Title 129, Chapter 27. In all cases, the approach used to evaluate BACT is the “top-down” BACT methodology as required by EPA. See the December 2003 permit application for additional discussion of the “top-down” BACT methodology.

The specific sources that are subject to BACT requirements as part of planned modifications to the Columbus plant are:

- The fermenter/CO<sub>2</sub> scrubber vent;
- The new denaturant (gasoline) storage tank;
- The new components in VOC service;
- The new rail car loading station;
- The modified ethanol process cooling towers;
- Gluten flash dryer #2;
- The fluid bed germ dryer; and
- The new gas-fired package boiler.

The remainder of this section presents the BACT analyses for each of these sources.

### **1.1 Fermenter/CO<sub>2</sub> Scrubber Vent**

The BACT analysis for the Fermenter/CO<sub>2</sub> Scrubber vent provided below includes a description of the source and its emissions, identification of possible control technology options for reducing emissions, an assessment of the economic, environmental, and energy impacts associated with each option, and a determination of BACT for the source.

#### **1.1.1 Process Description**

One of the key process operations in the alcohol plant is the fermentation of dextrose to produce ethanol. Fermentation involves metabolism of dextrose (produced by saccharification of corn starch) by cultivated yeasts in a series of closed tanks known as fermenters. These tanks are configured to provide the mixing, temperature, and residence time conditions needed for efficient fermentation. As part of the fermentation process, CO<sub>2</sub> is evolved at a rate of 6.3 pounds per gallon of alcohol (200 proof) produced. This CO<sub>2</sub> is captured in an active vent collection system that withdraws gas from the headspace in the fermenters. Vent gas from the fermenters consists almost entirely of CO<sub>2</sub> that is saturated with water and ethanol. Other species are also present in trace quantities (e.g., acetaldehyde).

The vent streams from the fermenters are collected and routed to the fermenter/CO<sub>2</sub> scrubber system where nearly all of the alcohol is removed and recovered to the process. The scrubbed CO<sub>2</sub> stream is discharged through a stack. The CO<sub>2</sub> scrubber uses water as the scrubbing agent. At Columbus, this system currently consists of two parallel packed tower scrubbers, but as part of the alcohol plant expansion, ADM plans to upgrade the CO<sub>2</sub> scrubber system to include a third scrubber to improve performance and reliability of the scrubber system. With this upgrade, two scrubbers will be on-line during normal operations and one of the scrubbers will serve as an installed spare. As described in the December 2003 PSD permit application, modifications are also planned to improve performance of the two existing scrubbers.

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<sup>1</sup> As discussed earlier, the modifications are significant for the following pollutants: NO<sub>x</sub>, SO<sub>2</sub>, PM, PM<sub>10</sub>, CO, VOC, H<sub>2</sub>SO<sub>4</sub> mist, fluorides (F), and lead (Pb)

In addition to the fermenter vent streams, ADM will route the non-condensable gas (NCG) vent streams from the distillation process to the CO<sub>2</sub> scrubbers. These streams contain similar concentrations of alcohol but are only about 10% (or less) of the volume of the CO<sub>2</sub> stream from the fermentation process. The scrubber system is designed to recover more than 99% of the VOC in the feed gas, and emissions from the scrubber system will be limited to 13.5 pounds per hour (annual average basis). Based on testing, HAP emissions are estimated to be at most 50% of this value (i.e., 6.8 lb/hr). Minor amounts of SO<sub>2</sub> are also emitted from this source, which currently has a permit limit of 2.5 lb/hr.

### **1.1.2 VOC Control Options**

Based on a review of the RBLC and other sources of information, the only control technology that has been used to control VOC emissions from alcohol fermenter vent streams is wet scrubbing. Only four relevant entries are found in the RBLC (over the last 10 years) and each of these uses a wet scrubber (see Attachment A). ADM also reviewed electronic permit files from recently permitted ethanol production facilities in select states (Illinois, Iowa, and Minnesota) and found that wet scrubbing is the primary technology that has been applied to this stream. VOC control efficiencies for such wet scrubbers are reported to range from 95 to 99%. High efficiencies are a result of the highly soluble nature of ethanol in water. Based on limited source testing, the CO<sub>2</sub> scrubber at Columbus is achieving VOC control efficiencies at the high end of this range and will continue to do so following the completion of the alcohol plant expansion project. ADM's CO<sub>2</sub> scrubber will be designed to achieve a VOC effluent concentration of 150 ppmv. Based on an estimated inlet loading of 30,000 ppmv, this equates to a VOC control efficiency of about 99.5%.

A second option for controlling VOC emissions from the fermenter vent stream is the use of thermal oxidation. Note that this option would not replace the CO<sub>2</sub> scrubber system since this scrubber is an integral part of the process used for recovering and producing alcohol. Instead, the thermal oxidizer would be installed downstream of the scrubber system to destroy VOC not captured by the scrubber. Due to the nature of the CO<sub>2</sub> scrubber exhaust, the scrubber effluent stream would have to be treated to raise the oxygen level from near zero to several percent so that sufficient oxygen would be present to allow the VOC to be oxidized. ADM estimates that at least 10% dilution of this stream would be required and that sufficient mixing of the CO<sub>2</sub> and dilution air stream would be needed upstream of the oxidizer to ensure good combustion. Assuming a control efficiency of 95%, the use of a thermal oxidizer would increase the overall VOC control efficiency of the fermenter vent stream from about 99.5% to 99.98%.

### **1.1.3 Impacts analysis of VOC Control Options and Proposed BACT**

ADM has made an assessment of the costs, benefits, and other impacts of the two VOC control technology options that are potentially applicable to the fermenter vent stream.<sup>1</sup> The results of this assessment are summarized in Table 1-1. This table shows that some additional VOC reductions could be provided by the use of an add-on thermal oxidizer downstream of the CO<sub>2</sub> scrubber. However, these additional reductions come at a substantial cost in terms of economic and energy impacts. Based on this assessment, ADM concludes that the additional cost of control (\$10,700/ton of VOC) and energy penalty (90 MMSCF of natural gas per year) do not justify the added VOC reductions provided by the thermal oxidizer.

Because of the high cost and limited benefits provided by a thermal oxidizer, the use of a packed scrubber is the top performing technology with acceptable impacts. For this reason, ADM concludes that BACT for the fermenter/distillation system vent stream is the use of wet scrubbing to achieve a VOC emissions limit of 13.5 lb/hr.

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<sup>1</sup> Control costs were estimated using OAQPS' CO\$T-AIR model for thermal oxidizers. See Attachment D for details.

**Table 1-1. BACT Impact Analysis Results for Fermenter/Distillation Vent Stream**

Parameter	Thermal Oxidation	Wet Scrubbing
Baseline VOC Emissions (tpy)	59.2	59.2
Reduction Efficiency	95%	Baseline
VOC Emissions Reduction (tpy)	56.3	Baseline
Annualized Cost	\$601,500	Baseline
Cost Effectiveness (\$/ton)	\$10,700	N/A
Environmental Impacts	Reduced HAP Emissions of 28.1 tpy	Baseline
	Increased $\text{NO}_x$ Emissions of 2.3 tpy	
	Increased CO Emissions of 3.8 tpy	
Energy Impacts	456 MWH/yr of electricity consumed	Baseline
	90 MMSCF/yr of natural gas consumed	

#### 1.1.4 HAP Control Options

The primary HAP present in the fermenter/ $\text{CO}_2$  scrubber vent is acetaldehyde. The same control technologies used to control VOC emissions are applicable to controlling HAP emissions from this stream. However, the wet scrubbing system is not as effective in controlling HAP emissions because acetaldehyde is not as soluble in water as ethanol is. ADM has concluded that BACT is compliance with the new VOC emissions limit. This conclusion is based on the high cost and energy impacts associated with the use of thermal oxidation for HAP control.

#### 1.1.5 $\text{SO}_2$ Control Options and Proposed BACT

ADM reviewed information in the RBLC and considered the potential for technology transfer to identify possible  $\text{SO}_2$  control options for the  $\text{CO}_2$  scrubber. Only one related source was identified in the RBLC and this source uses wet scrubbing to obtain 90%  $\text{SO}_2$  control. Considering the potential for technology transfer from other similar sources, ADM has concluded that wet scrubbing is the only practical technology for controlling  $\text{SO}_2$  emissions from the fermenters and other alcohol process vents that are routed to the  $\text{CO}_2$  scrubber. While there are other  $\text{SO}_2$  control options that might be considered (e.g., dry scrubbing), they offer no performance or cost advantages over wet scrubbing since the gas stream is already saturated with water. Additionally, the relatively low emissions rates of  $\text{SO}_2$  from the alcohol process make capital-intensive options unlikely to be cost-effective. The discussion that follows further examines the technical feasibility wet scrubbing for control of  $\text{SO}_2$  emissions from this vent stream.

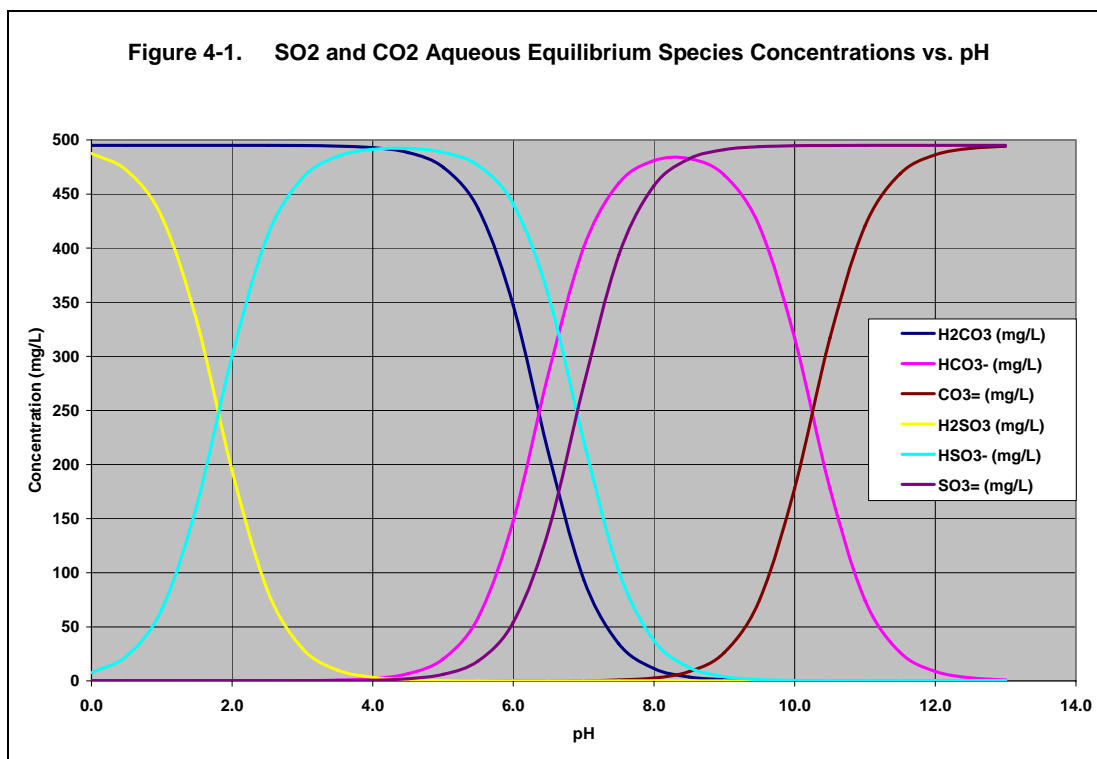
Wet scrubbing in the  $\text{CO}_2$  scrubber has technical limitations. Because the gas stream being scrubbed is nearly 100%  $\text{CO}_2$ , there is a practical upper limit on the operating pH of the scrubber. Specifically, ADM has determined that if the scrubber is operated above pH 4, significant quantities of  $\text{CO}_2$  would be scrubbed requiring significant use of caustic for limited benefit. This effect is illustrated by Figure 4-1, which shows how the equilibrium concentrations of  $\text{H}_2\text{CO}_3$  and  $\text{HCO}_3^-$  are affected by pH. As figure 4-1 shows, as the pH of a solution rises above 4, absorbed  $\text{H}_2\text{CO}_3$  would begin to dissociate to  $\text{HCO}_3^-$ , allowing more  $\text{CO}_2$  to be absorbed. At the same time, at pH 4, most absorbed  $\text{SO}_2$  (i.e.,  $\text{H}_2\text{SO}_3$ ) is converted to bisulfite ion (i.e.,  $\text{HSO}_3^-$ ). Thus, there is little improvement in the driving force to absorb  $\text{SO}_2$  above pH 4, while there is a significant increase in the driving force to absorb  $\text{CO}_2$ . This means that an attempt to maintain pH above 4 would increase  $\text{CO}_2$  absorption much more than it would increase  $\text{SO}_2$  absorption (i.e., little performance benefit would be derived from the pH increase while most of the added caustic would be used up creating sodium bicarbonate that would have to be disposed of in the plant's waste water). Thus ADM concludes that for the  $\text{CO}_2$  scrubber, the optimum operating pH is 4.

ADM performed an engineering evaluation of the performance of the CO<sub>2</sub> scrubber operating at an effluent pH of 3.5<sup>1</sup> and determined that a minimum of 90% SO<sub>2</sub> capture is expected. This analysis is based on the design parameters listed in Table 1-2. The SO<sub>2</sub> absorption equilibrium and operating lines for a scrubber based on the data in Table 1-2 are shown in Figure 4-2. As this figure shows, less than 2 transfer units (i.e., 6 feet of packing) are required to obtain 90% control of SO<sub>2</sub> emissions. Since the scrubber has at least 10 transfer units, there is adequate margin to assure that 90% SO<sub>2</sub> control is achieved at pH 3.5.

**Table 1-2. ADM Columbus Fermenter Scrubber Operating / Design Parameters**

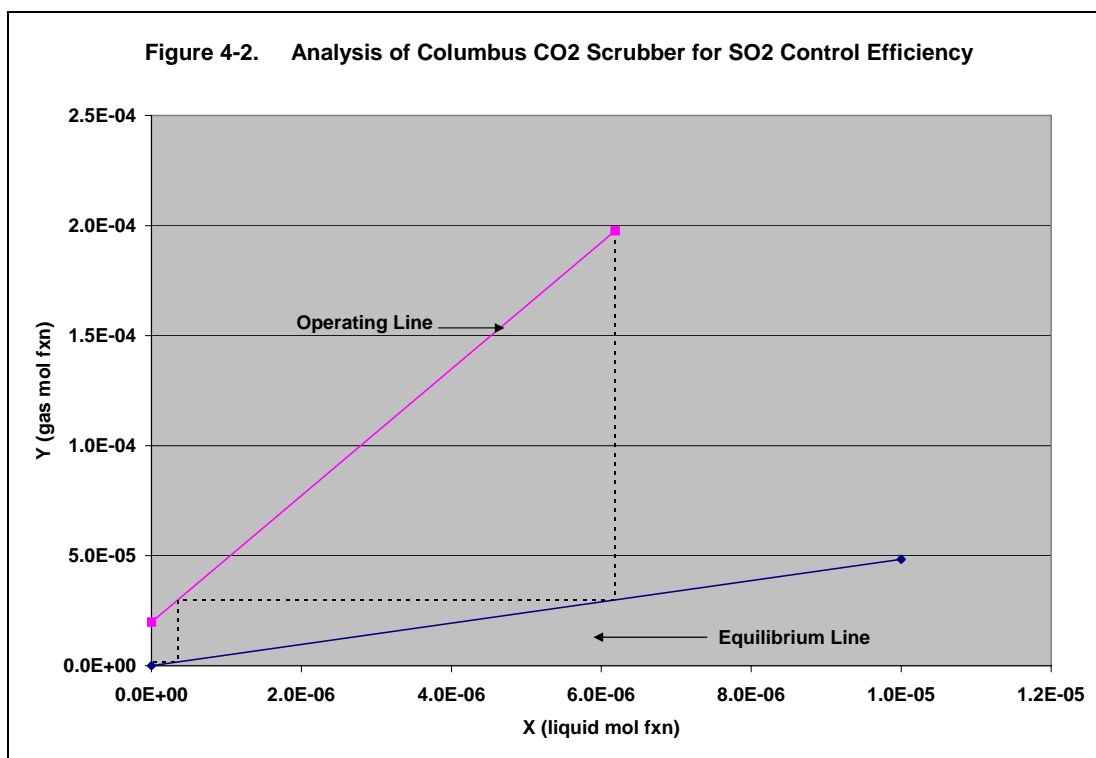
Parameter	Value
Fresh Water Make Up Rate	40 gpm
Packing Depth	30 feet
Minimum pH	3.5
Inlet SO <sub>2</sub> loading	25 lb/hr
Gas Flow	12,700 dscfm
Maximum Packing HTU (height of a transfer unit)	3 feet

Based on this analysis, ADM proposes that BACT for SO<sub>2</sub> from the fermenter/process vent stream is wet scrubbing at a minimum pH of 3.5. The emissions limit that corresponds to this technology option is 2.5 lb/hr SO<sub>2</sub>. Since this is the top-performing technology option, cost, energy, and environmental impacts were not evaluated.



<sup>1</sup> A pH of 3.5 was used in this analysis because of the inherent variability in pH measurements. Since caustic requirements will increase significantly above pH 4.0, ADM is proposing to operate at a minimum pH of 3.5. This provides some margin for error without incurring undue costs. Also, the proposed scrubber design is capable of obtaining at least 90% SO<sub>2</sub> control at pH 3.5.





## 1.2 New Denaturant (gasoline) Storage Tank

The BACT analysis for the new denaturant storage tank provided below includes a description of the source and its emissions, identification of possible control technology options for reducing emissions, an assessment of the economic, environmental, and energy impacts associated with each option, and a determination of BACT for the source.

### 1.2.1 Process Description

Gasoline is used to denature the alcohol produced by ADM at the Columbus plant. This denaturant is received by truck, stored in an internal floating roof tank, and then blended with the 200 proof alcohol produced by the fermentation/distillation/dehydration process. Denaturant is blended with 200 proof alcohol upstream of the 1 million gallon fuel alcohol storage tank at the Columbus plant. In the gasoline and alcohol storage tanks, vapors are emitted due to both working and breathing losses. Vapor losses from tanks that store denaturant are VOC and contain small quantities of HAP.

The planned increase in alcohol production capacity will result in an unacceptably low denaturant reserve using the existing tank and ADM has determined that the denaturant storage capacity must be increased. The total denaturant storage capacity needed is estimated at 105,000 gallons. ADM has not decided whether a new 105,000 gallon tank will be constructed or whether a smaller 62,500 gallon tank will be constructed to supplement the existing denaturant storage capacity. In either case, the new tank will be subject to BACT requirements for both VOC and HAP.

For purposes of this analysis, it is assumed that a 105,000 gallon tank will be constructed and that 100% of the denaturant will flow through this tank. ADM believes that this approach results in the most favorable estimates of impacts for purposes of determining BACT. U.S. EPA's TANKS 4.0 program has been used to estimate emissions from this new tank and emissions are projected to be approximately 1.1 tpy based on typical internal floating roof construction.

### **1.2.2 VOC and HAP Control Options and Proposed BACT**

Based on a review of the RBL, the applicable NSPS, and other sources of technical information (e.g., AP-42), the options for controlling organic vapor loss emissions from a gasoline storage tank include the following:

- Floating roof tank (internal or external);
- Fixed roof tank equipped with vapor collection and control equipment.

In either case, ADM is required to meet the applicable provisions of the NSPS. While the use of fixed roof tanks with vapor collection may provide somewhat lower emissions than a floating roof tank, ADM has concluded that the small reduction in emissions that might be achieved using this approach comes at a substantial increase in cost and thus, this option should not be considered economically feasible. ADM therefore proposes that BACT (VOC and HAP) for the new denaturant tank be an internal floating roof that meets the applicable requirements of 40 CFR 60, Subpart Kb.

### **1.3 Components in VOC service**

As part of the expansion of the Columbus alcohol plant, ADM will add some additional process piping components such as valves and flanges. Emissions from leaking valves, flanges, pumps, and other process and piping sources have long been recognized as fugitive emissions sources in various industries. The process and piping fugitive sources in ADM's alcohol production plant are primarily sources of ethanol (VOC) emissions, and not HAP. However, based on other testing done by ADM, it is reasonable to conclude that some small fraction of these fugitive VOC emissions is HAP (e.g., acetaldehyde).

Based on a review of the RBL and other technical sources of information, the only technically feasible control option for these sources of VOC/HAP emissions is a leak detection and repair (LDAR) program. At the Columbus plant, process and piping fugitive sources are subject to the requirements of 40 CFR 60, Subpart VV which requires that ADM implement an LDAR program for fugitive VOC emissions in its alcohol plant. The requirements of Subpart VV help ensure that fugitive VOC emissions are minimized. Since compliance with Subpart VV will also minimize HAP emissions from the alcohol plant fugitive VOC sources, ADM concludes that the requirements of Subpart VV represent BACT for these emissions sources.

### **1.4 New Rail Car Loading Station**

As part of the alcohol plant expansion at Columbus, ADM will add an additional railcar load-out position. When alcohol is loaded into railcars for shipment offsite, VOC is emitted when vapor in the transport vehicles is displaced by the liquid being loaded. Most of the VOC in this displaced vapor is ethanol, which is not a HAP. However, depending on the composition of the vapors that are displaced from the transport vehicles, some HAP may also be emitted.

ADM recently installed and is operating a thermal oxidizer (more specifically an open flame flare) to control emissions of VOC from the loadout operations at the Columbus plant. This flare will also serve to control emissions of organic HAP, which are the only expected type of HAP emissions from the loading operation. ADM proposes to route displaced vapors from the new rail loadout position to the existing flare. This flare has a design capacity that is capable of handling the additional vapor load from the new rail loadout station.

A review of available information on the control of organic VOC emissions indicates that thermal oxidation is the single most commonly used technology to meet BACT requirements for sources that cannot be controlled through source reduction or pollution prevention measures. For these reasons, ADM concludes thermal oxidation of the loadout vapors is the top performing technology for control of both VOC and HAP emissions. Since a flare has already been installed to collect and oxidize emissions from the Columbus plant's loadout operations, ADM concludes that BACT is the 95% VOC control requirement for the existing flare.

### **1.5 Modified Ethanol Process Cooling Towers**

Cooling water is needed to support the ethanol plant and additional cooling water will be required as a result of the expansion. ADM's current plans call for increasing the flow to the existing cooling towers. This change will result in an increase in PM and PM<sub>10</sub> emissions. No HAP emissions are associated with these cooling towers as they do not use chromium. The cooling towers are equipped with drift eliminators for control of PM/PM<sub>10</sub> emissions. The estimated drift rate from these towers is 0.008%. A search of RBLC database identified high efficiency drift or mist eliminators as the only BACT control option. The existing high efficiency drift eliminators are proposed as BACT for these towers resulting an estimated 20.8 tons per year of PM and 12.5 tons per year of PM<sub>10</sub> emissions from the ethanol cooling towers.

## **1.6 Gluten Flash Dryer #2**

At the Columbus plant, gluten meal is separated from corn as part of the wet milling process. This high-protein byproduct is first dewatered and then sent to one of two parallel gluten flash dryers (GFD). In these dryers, the moist gluten is conveyed into a rising stream of hot air, which conveys and dries the gluten. Dry gluten product is recovered in a cyclone and the cyclone exhaust is routed to a wet scrubber for particulate and SO<sub>2</sub> control.

ADM is planning on upgrading the capacity of GFD #2 by installing a new 65 MMBtu/hr low-NO<sub>x</sub> burner to replace the existing 26 MMBtu/hr burner in this unit. With this new burner, the dryer's capacity is projected to increase by about 13%, which in turn will result in a slight increase in utilization of other operations in the Columbus plant.<sup>1</sup> The gluten flash dryers are a source of PM, PM<sub>10</sub>, SO<sub>2</sub>, NO<sub>x</sub>, CO, VOC, and HAP. Modification of this dryer subjects it to BACT review for each of these pollutants.

### **1.6.1 VOC and HAP Control Technology Review**

The Columbus gluten flash dryers are not required to implement any emissions reduction projects under the National Consent Decree. However, in the December 2003 permit application, ADM proposed a VOC emissions limit for GFD #2 of 19.7 lb/hr (86.3 tons per year) pursuant to Paragraph 39(b) of the Consent Decree. HAP emissions from this unit are estimated to be a maximum of 10% of the VOC emissions (8.6 tons per year).

Based on a review of the RBLC, no control technologies have previously been applied as BACT to control VOC emissions from gluten flash dryers. Only two entries are found in the RBLC (over the last 10 years), and in both cases, no controls were identified as being feasible for VOC control from this source type.

Considering the nature of the source, ADM has determined that the two potentially applicable VOC control technologies are wet scrubbing and the use of an add-on thermal oxidation device. Since GFD #2 is already equipped with a wet scrubber, this represents the baseline level of VOC emissions control for this source. Based on testing, the baseline controlled VOC emission rate is 19.7 lb/hr. Considering the planned 13% expansion of the dryer's capacity, the baseline VOC emissions are projected to increase to 22.2 lb/hr. Thus, evaluation of the effectiveness of thermal oxidation is based on this level of emissions entering a thermal oxidizer. A thermal oxidizer is expected to provide a minimum of 95% control of the baseline (post-scrubber) VOC emissions.

ADM evaluated the impacts of applying a recuperative thermal oxidizer to GFD #2. The results of this assessment are summarized in Table 1-3. As this table shows, the use of thermal oxidation has a very high economic impact of over \$34,000 per ton of VOC controlled. Further, it results in an increase in NO<sub>x</sub> and possibly CO emissions of more than 20 tpy (combined). These impacts occur because VOC is present in low concentrations in the flash dryer exhaust gas stream, requiring a large oxidizer with substantial natural gas consumption to achieve the VOC reductions. Based on this assessment, ADM concludes that BACT for VOC emissions from GFD #2 is the use of a wet scrubber to achieve a VOC emissions limit of 22.2 lb/hr.

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<sup>1</sup> Note that the flash dryers at Columbus utilize boiler flue gas as drying "air" to reduce energy requirements provided by firing natural gas in the dryer itself (i.e., less firing of the dryer burner is required when boiler flue gas is routed to the dryers). Because much of the drying energy comes from the boiler flue gas, the larger burner only will enable a modest increase in dryer capacity. Gluten flash dryer #2 receives flue gas from Boilers 3 and 4 and the capacity increase provided by the new burner primarily results from being able to run the dryer at high rates when one or both of these boilers are out of service.

As table 1-3 also shows, use of a thermal oxidizer will also result reduction in HAP emissions of 8.6 tons per year. Considering the cost of achieving these reductions (i.e., 10 times the cost of achieving the VOC reductions), ADM concludes that BACT for HAP emissions from the gluten flash dryer is compliance with the VOC BACT limit of 22.2 lb/hr.

**Table 1-3.  
Economic, Energy and Environmental Impacts of  
Applying Thermal Oxidation to GFD#2**

Parameter	Value
Technology	Thermal Oxidation (recuperative-type)
Baseline Emissions	86.3 tpy
Reduction Efficiency	95%
Emissions Reduction	82.0 tpy
Annualized Cost	\$2.80 million
Cost Effectiveness	\$34,200/ton
Environmental Impacts	Increased NO <sub>x</sub> & CO Emissions (20 tpy)
	Reduced HAP Emissions of 8.2 tpy
Energy Impacts	492 MMSCF/yr of Natural Gas Consumed
	2,517 MWH of Electricity Consumed

Secondary sources or organic HAP emissions from gluten processing are the Gluten Cooling baghouses (SV-17 and SV-19) and the Gluten Recycle baghouse (SV-44). ADM has conservatively estimated that HAP emissions from these sources are at most 0.5 lb/hr in a flow stream of 68,500 scfm. These emissions represent organic HAP that may remain in the product after drying and then be stripped from the product by the air used to convey and cool the gluten. Because the HAP concentration in this stream is much more dilute than the concentration in the dryer exhaust, the cost of control will be much higher than the cost of control for the gluten dryers. ADM estimates that the HAP control cost-effectiveness of thermal oxidation for this combined stream exceeds \$1,000,000 per ton. The added HAP reductions that would be provided by this technology cannot be justified by the high cost of installing and operating additional control equipment on these sources.

### 1.6.2 CO Control Technology Review

CO emissions from GFD #2 at the Columbus plant result from incomplete combustion of the natural gas in the dryer's burner as well as from CO present in the flue gas from Boilers #3 and 4 that is used in the drying process. The boiler flue gas CO emissions are not new emissions caused by the flash dryer, but instead are emissions with their own BACT limit determined at the time the boilers were constructed. Thus, it is important to recognize that the BACT limit for GFD #2 should exclude CO that is "imported" from Boilers 3 and 4 (i.e., the boiler CO emissions occur independently from dryer design or operation, and these emissions actually off-set additional CO production that could result from firing the dryer's burner at higher rates).

To identify the types of CO controls used by the food and agricultural products industry, the RBLC database was searched for BACT determinations, from 1994 to present, for gluten dryers. This review was used to identify the control technologies that in the past have been used in the industry, as well as the accompanying control efficiencies and BACT emission limits of each of the controls listed. The results of this search as it relates to CO emissions are summarized in Table 1-4.

As shown, for CO, the only control technologies identified for gluten dryers are the use of combustion control and natural gas as fuel. Another CO control technology known to be used on corn mill dryers is thermal oxidation. However, as described earlier, the use of thermal oxidation will produce additional CO emissions from the combustion of auxiliary fuel. Assuming a CO emissions factor of 84 lb/MMSCF (AP-42, Table 1.4-1, 7/98 edition), a thermal oxidizer is projected to produce about 4.7 lb/hr of CO emissions from the gas combusted in the oxidizer burner. The current baseline CO emissions limit for this dryer is 4.21 lb/hr and the increase in capacity is

projected to result in a CO emissions limit of 4.74 lb/hr.<sup>1,2</sup> Assuming that the oxidizer can reduce CO emissions from the dryer by 90% or 4.26 lb/hr, a net increase in CO emissions would result from use of a thermal oxidizer on GFD #2 because the CO produced by the oxidizer would be more than the CO destroyed in the oxidizer (i.e., 4.7 lb/hr produced by the thermal oxidizer burner vs. 4.26 lb/hr destroyed). This situation occurs because CO emissions from GFD #2 are already quite low, and they are projected to remain at low levels after the burner replacement. For this reason, thermal oxidation is not considered a technically feasible option for controlling CO emissions from GFD #2.

**Table 1-4. RBLC Data on CO BACT Limits for Gluten Dryers**

RBLCID	Facility	Permit Date	Process	Max Heat Input (MMBtu/hr)	CTRLDESC	Limits lb/MMBtu
MN-0026	ADM (formerly MCP)	8/9/1995	Corn Gluten Dryer	39	CO – Fuel spec: fuel limited to natural gas or biogas generated on-site.	0.154*
NE-0016	Cargill, Inc.	4/25/1996	Gluten Flash Dryer	45	CO – None specified	0.073
IN-0075	Grain Processing Corp.	6/10/1997	Gluten Dryer	25	CO – Good combustion control.	0.060**

\* Calculated from BACT limit of 6 lb/hr and 39 MMBtu/hr heat input.

\*\* Calculated based on a natural gas heating value of 1020 Btu/SCF

Based on information in the RBLC as well as the individual characteristics of GFD #2 which make thermal oxidation technically infeasible, ADM concludes that good combustion control is the only technically feasible control option for CO emissions from GFD #2. ADM proposes a CO emissions limit of 4.74 lb/hr for this dryer. This limit is equivalent to an emissions rate of 0.073 lb/MMBtu at 65 MMBtu/hr, a value on the low-end of the \ gluten dryer BACT limits found in the RBLC. Compliance with this limit should be determined in the absence of flue gas from Boilers #3 and 4 since CO emissions from these boilers are restricted by a separate limit and BACT determination.

### 1.6.3 PM / PM<sub>10</sub> Control Technology Review

ADM has reviewed the RBLC for PM/PM<sub>10</sub> control technology options for GFD #2. The results of this review are summarized in Table 1-5. As this table shows, the use of cyclones and wet scrubbers in combination is typical of the technology used to control particulate emissions from this source category. The emissions limits associated with this technology range from 0.01 to 0.45 grains per dscf. ADM did not specifically evaluate other particulate control technology options for this source for the following reasons:

- The source is already equipped with PM/PM<sub>10</sub> control technology similar to that determined to be BACT for other similar sources; and
- Retrofit of another type of control device (e.g., a fabric filter) would be expensive and provide little additional reduction in emissions (i.e., it would not be cost-effective).

Based on the technology in place and the emissions limits that are typical for this type of technology, ADM concludes that BACT for PM/PM<sub>10</sub> for GFD #2 is a limit of 0.015 gr/dscf. This limit includes both filterable and condensable PM<sub>10</sub> fractions.

<sup>1</sup> This CO limit is that proposed in the December 2003 application based on test data and pursuant to Paragraph 39(b) of the National Consent Decree.

<sup>2</sup> This value (4.74 lb CO/hr) is equivalent to a CO emissions rate of 0.073 lb/MMBtu at a burner rate of 65 MMBtu/hr.

**Table 1-5. RBLC Data on PM/PM<sub>10</sub> BACT Limits for Gluten Dryers**

Company	RBLCID	Source	Pollutant	Technology	Limit
ADM (formerly MCP)	MN-0039	Corn Gluten Dryer	PM/PM <sub>10</sub>	Wet Scrubber	0.019 gr/dscf
Grain Processing Corp	IN-0075	Gluten Dryer	PM <sub>10</sub>	Wet Scrubber	0.01 gr/dscf
Cargill	NE-0016	Gluten Flash Dryer	PM	Cyclone/Wet Scrubber	0.045 lb/MMBtu
Cargill	NE-0016	Gluten Flash Dryer	PM <sub>10</sub>	Cyclone/Wet Scrubber	0.027 lb/MMBtu
Cargill	IA-0029	Gluten Flash Dryers (2)	PM	Wet Scrubber	0.025 gr/dscf
ADM (formerly MCP)	NE-0014	Gluten Flash Dryer #1	PM	Cyclone/Wet Scrubber	0.009* gr/dscf
ADM (formerly MCP)	NE-0014	Gluten Flash dryer #2	PM	Cyclone/Wet Scrubber	0.01* gr/dscf

\* These BACT limits were based on filterable PM only. Tests on a similar GFD at ADM's Marshall, MN plant have shown that filterable PM accounts for about 2/3 of the total PM/PM<sub>10</sub> (i.e., filterable plus condensable PM/ PM<sub>10</sub>). Thus, a limit of 0.01 gr/dscf for filterable PM is equivalent to a limit of 0.015 for filterable plus condensable PM/ PM<sub>10</sub>.

#### 1.6.4 NO<sub>x</sub> Control Technology Review

NO<sub>x</sub> emissions result from the combustion of natural gas in the gluten flash dryer. Generally, gluten flash dryers fired with natural gas have relatively low NO<sub>x</sub> emissions (less than 0.10 lb NO<sub>x</sub>/MMBtu) because there is no fuel bound nitrogen in natural gas and combustion takes place in a relatively low temperature setting. Note also that in the case of the Columbus gluten flash dryers, NO<sub>x</sub> enters the process in the flue gas from the gas-fired boilers. The boiler flue gas NO<sub>x</sub> emissions are not new emissions caused by the dryer, but instead are emissions with their own BACT limit determined at the time of the boilers construction. Thus, it is important to recognize that the BACT limit for GFD #2 should exclude NO<sub>x</sub> that is "imported" from Boilers 3 and 4 (i.e., the boiler NO<sub>x</sub> emissions occur independently from dryer design or operation and these emissions actually off-set additional NO<sub>x</sub> production that could result from firing the dryer's burner at higher rates).

To identify the types of NO<sub>x</sub> controls used for reducing emissions from similar sources, the RBLC database was searched for BACT determinations on gluten dryers. Table 1-6 summarizes the results of this search. As this table shows, only combustion controls have been used to control NO<sub>x</sub> from gluten dryers.

Generally there are a number of NO<sub>x</sub> control technologies that are used to control NO<sub>x</sub> emissions from gas-fired combustion sources including selective catalytic reduction (SCR), selective non catalytic reduction (SNCR), and combustion controls such as low NO<sub>x</sub> burners, low excess air operation, and flue gas recirculation. However, the technical and economic feasibility of each of these control technologies are based on process factors (e.g., flue gas temperatures and contaminant loading), operating schedule, and control efficiency capability. The following subsections discuss the technical feasibility of applying SCR and SNCR controls to corn gluten dryers. The SCR and SNCR discussion provides the technical and economic understanding as to why these technologies are not used to control NO<sub>x</sub> from gluten dryers.

**Table 1-6. Summary of RBLC Information for Gluten Dryers - NO<sub>x</sub>**

<b>RBLCID</b>	<b>FACILITY</b>	<b>PERMIT DATE</b>	<b>PROCESS</b>	<b>CTRLDESC</b>	<b>LIMIT (lb/MMBtu)</b>	<b>LIMIT (lb/hr)</b>
MN-0026	ADM (formerly MCP)	8/9/95	CORN GLUTEN DRYER (39 MMBtu/hr)	Flue gas recirculation (FGR) and combustion control	0.079	3.07
IA-0029	CARGILL, INC.	9/25/95	GLUTEN FLASH DRYERS (2) (25 MMBtu/hr)	Low-NO <sub>x</sub> Burner; Mfr: Barr-Murphy	0.14	3.5
NE-0014	ADM (formerly MCP)	7/12/95	Gluten Meal Flash Dryer #2 (26 MMBtu/hr)	Good combustion control, FGR from boiler	0.10	2.6
NE-0014	ADM (formerly MCP)	7/12/95	Gluten Meal Flash Dryer #1 (55 MMBtu/hr)	Good combustion control, FGR from boiler	0.079	4.3
NE-0016	CARGIL, INC	4/25/96	Gluten Flash Dryer (45 MMBtu/hr)	Good combustion control, FGR from boiler	0.20	9.0
IN-0075	GRAIN PROCESSING	6/10/97	GLUTEN DRYER (25 MMBtu/hr)	Water quench and Low-NO <sub>x</sub> burner	0.06	1.5

#### **1.6.4.1 SCR Technology**

The use of SCR technology is considered to be both technically and economically infeasible for application to gluten dryer flue gases for the following reasons:

- The dryer exhaust gas would have to be heated from 135°F or 350 °F (after wet scrubber – before wet scrubber) to ~600 °F (SCR operating temperature) followed by heat recovery. This complex arrangement makes the annual cost of control unacceptably high due to the small amount of NO<sub>x</sub> that could be reduced by the addition of SCR technology; and
- The sticky, organic nature of particulate matter from this source could rapidly foul the SCR catalyst making SCR technology infeasible.

These technical and economic issues have prevented the use of SCR technology for gluten dryers as demonstrated by the RBLC review. As such, SCR technology is not considered in the BACT analysis hierarchy.

#### **1.6.4.2 SNCR Technology**

The use of SNCR technology is considered to be both technically and economically infeasible for application to gluten dryer flue gases for the following reasons:

- The dryer exhaust gas would have to be heated from 100 °F or 350 °F (after wet scrubber – before wet scrubber) to about 1600 °F (SNCR operating temperature) followed by heat recovery. This complex arrangement makes the annual cost of control unacceptably high due to the small amount of NO<sub>x</sub> that could be reduced by the addition of SNCR technology;
- The formation of ammonium salts will cause fouling of downstream emission control and heat recovery equipment; and
- The formation of ammonium salts will cause an increase in dryer PM<sub>10</sub> emissions and opacity.

These technical and economic issues have prevented the use of SNCR technology for gluten dryers as demonstrated by the RBLC review, which found no SNCR applications on such dryers. As such, SNCR technology is not considered in the BACT analysis hierarchy.

#### **1.6.4.3 NO<sub>x</sub> Control Technology Hierarchy**

The results of the technology review identified only combustion controls as being technically feasible for controlling NO<sub>x</sub> emissions from the gluten dryer. The RBLC search identified six NO<sub>x</sub> emission limits established between 1994 June 2004. As Table 1-6 shows, the NO<sub>x</sub> emission limits for gluten dryers range from 0.06 lb/MMBtu to 0.14 lb/MMBtu based on the use of combustion control technologies. In addition, recently

permitted/installed dryers at ADM corn plants typically have achieved NO<sub>x</sub> emission rates of 0.06 lb/MMBtu or lower.

#### 1.6.4.4 Proposed BACT Emission Rate for NO<sub>x</sub>

Consistent with the identified RBLC BACT determinations, ADM propose to use a natural gas-fired, low NO<sub>x</sub> burner with a proposed emission rate at the low end of the range found in the RBLC. Specifically, ADM proposes a NO<sub>x</sub> BACT limit of 0.06 lb/MMBtu (3.9 lb NO<sub>x</sub> per hour) for GFD #2. Compliance with this limit should be determined in the absence of flue gas from Boilers #3 and 4 since NO<sub>x</sub> emissions from these boilers are addressed by a separate BACT limit. Also, use of boiler flue gas for drying actually reduces the level of NO<sub>x</sub> produced in the flash dryer's burner.

#### 1.6.5 SO<sub>2</sub> Control Technology Review

SO<sub>2</sub> emissions from the gluten flash dryers at the Columbus plant originate from two sources. The first and primary source of SO<sub>2</sub> emissions is from dissolved SO<sub>2</sub> present in the wet gluten. Drying the gluten vaporizes some of the dissolved SO<sub>2</sub> as a gaseous emission. The second source of SO<sub>2</sub> is from the small amount of sulfur present in the fuel combusted in the dryer itself.

ADM reviewed the RBLC to identify SO<sub>2</sub> control technologies that have been applied as BACT for this source category. The results of this review are summarized in Table 1-7. As this table shows, only two "technologies" are being applied as BACT for this source category: wet scrubbing and the use of low-sulfur fuel. Although other technologies are theoretically feasible for application to this source (e.g., dry scrubbing), because GFD #2 is already equipped with a wet scrubbing system for SO<sub>2</sub> control, such alternative technologies provide little or no potential improvement in SO<sub>2</sub> control at substantial added cost. Thus, the only technology that is practical to consider for application to this source (from an economic, energy, and environmental impact perspective) is the use of wet scrubbing with caustic addition.

**Table 1-7. Summary of RBLC Information for Gluten Dryers – SO<sub>2</sub>**

Company	RBLCID	Source	Technology	Limit(s)
ADM (formerly MCP)	NE-0014	Gluten Flash dryer #2	Cyclone/Wet Scrubber (w/ caustic addition)	0.081 lb/MMBtu 2.1 lb/hr
ADM (formerly MCP)	MN-0026	Corn Gluten Dryer	Fuel spec: fuel limited to natural gas or biogas generated on-site.	0.081 lb/MMBtu* 3.15 lb/hr
Cargill	IA-0029	Gluten Flash Dryers (2)	Wet Scrubber w/ Caustic	0.13 lb/MMBtu* 3.25 lb/hr

\* Value calculated from heat input and lb/hr limits.

Wet scrubbing with caustic addition is the top performing technology for gluten flash dryers and this technology is already installed on GFD #2 at the Columbus plant. The current emissions limit for this source is 2.1 lb/hr. ADM proposes that BACT for the modified dryer to be based on this control efficiency and adjusted upward to account for the increase in dryer throughput of 13%. Thus the new SO<sub>2</sub> BACT limit for GFD #2 is proposed to be 2.4 lb/hr.

#### 1.7 Fluid Bed Germ Dryer (FBGD)

At the Columbus plant, corn germ is separated from corn as part of the wet milling process. This byproduct is first dewatered and then sent to one of four germ dryers. Three of these dryers are steam-heated and one is a gas-fired fluidized bed germ dryer (FBGD). In the FBGD, the moist germ is dried by a rising stream of hot air that is heated by direct mixing with natural gas combustion products. Dry germ product is recovered in a cyclone and the cyclone exhaust vented to the atmosphere.

ADM is planning on upgrading the capacity of the FBGD by installing a new 55 MMBtu/hr low-NO<sub>x</sub> burner to replace the existing 36.4 MMBtu/hr burner in this unit. With this new burner, the dryer's capacity is projected to



increase by about 25%. The FBGD is a source of PM, PM<sub>10</sub>, SO<sub>2</sub>, NO<sub>x</sub>, CO, VOC, and HAP. As a result, modification of this dryer subjects it to BACT review for each of these pollutants. Table 1-8 summarizes the baseline (pre-modification emissions limits for this dryer).

**Table 1-8. Baseline Emissions Limits for the Columbus Fluid Bed Germ Dryer**

Pollutant	Emissions Limit	Comment
VOC	6.0 lb/hr	As described in 12/2003 PSD application.
NO <sub>x</sub>	0.1 lb/MMBtu	Permit limit.
CO	5.9 lb/hr	As described in 12/2003 PSD application.
PM <sub>10</sub>	1.6 lb/hr	Permit limit.
SO <sub>2</sub>	None	Unit does not currently have a limit on SO <sub>2</sub> .

### 1.7.1 VOC and HAP Control Technology Review

The Columbus FBGD is not subject to any emissions reduction projects under the National Consent Decree. However, in the December 2003 permit application, ADM proposed a VOC emissions limit for the FBGD of 6.0 lb/hr (26.3 tons per year) pursuant to Paragraph 39(b) of the Consent Decree. HAP emissions from this unit are estimated to be a maximum of 10% of the VOC emissions (2.6 tons per year).

Based on a review of the RBLC, no control technologies have previously been applied as BACT to control VOC emissions from germ dryers. The RBLC contains only one entry (over the last 10 years), and no controls were identified as being feasible for VOC control from this source type.

Considering the nature of the source, ADM has determined that the two potentially applicable VOC control technologies are wet scrubbing and the use of an add-on thermal oxidation device. Based on testing, the baseline uncontrolled VOC emission rate is 6.0 lb/hr. Considering the planned 25% expansion of the dryer's capacity, the baseline VOC emissions are projected to increase to 7.5 lb/hr after the modification. Thus, evaluation of the effectiveness of wet scrubbing and thermal oxidation is based on this level of emissions entering the control device. A wet scrubber is expected provide 80% control of the baseline VOC emissions while a thermal oxidizer is expected to provide 95% control.<sup>1</sup>

ADM evaluated the impacts of applying a wet scrubber and a recuperative thermal oxidizer to the Columbus FBGD. The results of this assessment are summarized in Table 1-9.<sup>2</sup> The top performing technology, thermal oxidation, has a very high economic impact of over \$68,000 per ton of VOC controlled. Further, it results in an increase in NO<sub>x</sub> emissions of about 9 tpy.<sup>3</sup> These impacts occur because VOC is present in low concentrations in the germ dryer exhaust gas stream, requiring a large oxidizer with substantial natural gas consumption to achieve the VOC reductions. Based on this assessment, ADM concludes that thermal oxidation has unacceptable impacts and should not be considered as BACT for the FBGD.

The next best performing technology is the use of a wet scrubber. This technology has been applied in corn mills for VOC control on other sources (e.g., fermenter vents), but has not been applied as BACT for fluidized bed germ dryers. As Table 1-9 shows, wet scrubbing has a relatively high economic impact of approximately \$5,200/ton of VOC controlled. However, the use of a wet scrubber is also projected to reduce HAP emissions by 50% and SO<sub>2</sub> by

<sup>1</sup> Higher control efficiencies are projected for ethanol, but lower efficiencies for VOC like acetaldehyde. Based on the measured ethanol content of the VOC emitted from this dryer, an overall VOC control efficiency of 80% is a reasonable target for this source using wet scrubbing.

<sup>2</sup> U.S. EPA's CO\$T-AIR algorithm for recuperative thermal oxidizers was used to estimate costs. See Attachment D for details.

<sup>3</sup> NO<sub>x</sub> and CO emissions estimates are based on the estimated natural gas firing rate for the oxidizer using the CO\$T-AIR algorithms and emissions factors of 50 lb NO<sub>x</sub> and 84 lb CO per million standard cubic feet of gas fired. Process CO emissions are estimated to be reduced by 90% by the oxidizer.

90% with no increase in NO<sub>x</sub> or CO emissions. These added environmental benefits make the installation of a wet scrubber (packed tower) BACT for this source. Consistent with the BACT analysis, ADM proposes that BACT for VOC emissions be the installation of a wet scrubber with a VOC emissions limit of 1.5 lb/hr.

As table 1-9 also shows, use of a wet scrubber will also result reduction in HAP emissions of 1.7 tons per year. Since the wet scrubber has been determined to be BACT for VOC, ADM concludes that BACT for HAP emissions should be compliance with the VOC BACT limit of 1.5 lb/hr.

**Table 1-9. Economic, Energy and Environmental Impacts of Applying Wet Scrubbing and Thermal Oxidation to the Columbus FBGD**

Parameter	Thermal Oxidation	Wet Scrubbing
Baseline VOC Emissions (tpy)	32.9	32.9
Reduction Efficiency	95%	80%
VOC Emissions Reduction (tpy)	31.2	26.3
Annualized Cost (\$10 <sup>6</sup> )	\$2.12	\$0.14
Cost Effectiveness (\$/ton)	\$68,100	\$5,200
Environmental Impacts	Increased NO <sub>x</sub> Emissions of 9.1 tpy	Reduced SO <sub>2</sub> emissions of 18 tpy.
	Reduced HAP Emissions of 3.1 tpy	Reduced HAP emissions of 1.7 tpy
	Net Reduction in CO Emissions of 10.8 tpy	No impact on NO <sub>x</sub> or CO emissions
Energy Impacts	1,880 MWH/yr of electricity consumed	308 MWH/yr of electricity consumed
	365 MMSCF/yr of natural gas consumed	No natural gas consumed

Secondary sources or organic HAP emissions from germ processing are the Germ Cooling baghouses (SV-9 and SV-12). ADM has conservatively estimated that HAP emissions from these sources are at most 1.2 lb/hr in a flow stream of 108,000 scfm. These emissions represent organic HAP that may remain in the product after drying and then be stripped from the germ by the air used to convey and cool the germ. Because the HAP concentration in this stream is much more dilute than the concentration in the dryer exhaust, the cost of control will be much higher than the cost of control for the germ dryers. ADM estimates that the HAP control cost-effectiveness of thermal oxidation for this combined stream exceeds \$750,000 per ton. The added HAP reductions that would be provided by this technology cannot be justified by the high cost of installing and operating additional control equipment on these sources.

### 1.7.2 CO Control Technology Review

Emissions of CO from the FBGD at the Columbus plant result from incomplete combustion of the natural gas in the dryer's burner. To identify the types of CO controls used in similar dryers, the RBLC database was searched for germ dryer BACT determinations, from 1994 to present. This review was used to identify the control technologies that in the past have been used in the industry, as well as the accompanying control efficiencies and BACT emission limits of each controls listed. The results of this search as it relates to CO emissions are summarized in Table 1-10.

As shown, for CO, the only control technology identified for germ dryers is the use of combustion control. Another CO control technology known to be used on corn mill dryers is thermal oxidation. However, as described earlier, the use of thermal oxidation will produce additional CO emissions from the combustion of auxiliary fuel. Assuming a CO emissions factor of 84 lb/MMSCF (AP-42, Table 1.4-1, 7/98 edition), a thermal oxidizer is projected to produce about 2.8 lb/hr of CO emissions from the gas combusted in the oxidizer burner. The current baseline CO emissions limit for this dryer is 5.9 lb/hr and the increase in capacity is projected to result in a CO emissions limit of

7.4 lb/hr.<sup>1,2</sup> Assuming that the oxidizer can reduce CO emissions from the dryer by 90% or 6.6 lb/hr, only a small net decrease in CO emissions would result from use of a thermal oxidizer on the FBGD because the CO produced by the oxidizer would off-set a significant fraction of the CO destroyed in the oxidizer (i.e., 2.8 lb/hr produced by the thermal oxidizer burner vs. 6.6 lb/hr destroyed). Given the annualized cost of thermal oxidizer, the net reduction in CO emissions would result in a cost effectiveness value of over \$120,000 per ton. Even if both CO and VOC reductions are considered together and the 7.1 tpy increase in NO<sub>x</sub> emissions is ignored, the cost-effectiveness value would be over \$50,000 per ton.

**Table 1-10. RBLC Data on CO BACT Limits for Germ Dryers**

<b>RBLCID</b>	<b>Facility</b>	<b>Permit Date</b>	<b>Process</b>	<b>Max Heat Input (MMBtu/hr)</b>	<b>CTRLDESC</b>	<b>Limits lb/MMBtu</b>
NE-0016	Cargill, Inc.	4/25/1996	Germ Dryer	50	CO – N(No controls feasible)	0.073
IN-0075	Grain Processing Corp.	6/10/1997	Germ Dryer	16.5	CO – Good combustion control.	0.060*

\* Calculated based on a natural gas heating value of 1,020 Btu/SCF.

Based on information in the RBLC as well as the individual characteristics of the FBGD which make thermal oxidation economically infeasible, ADM concludes that good combustion control is the only viable control option for CO emissions from this dryer. ADM proposes a CO emissions limit of 4.02 lb/hr for this dryer. This limit is equivalent to an emissions rate of 0.073 lb/MMBtu at 55 MMBtu/hr.

### 1.7.3 PM / PM<sub>10</sub> Control Technology Review

ADM has reviewed the RBLC for PM/PM<sub>10</sub> control technology options for the Columbus FBGD. The results of this review are summarized in Table 1-11. As this table shows, the use of cyclones and wet scrubbers in combination is typical of the technology used to control particulate emissions from this source category. The emissions limits associated with this technology range from 0.01 to 0.45 grains per dscf. ADM did not specifically evaluate other particulate control technology options for this source for the following reasons:

- The BACT determination for VOC will result in the installation of a wet scrubber which should help reduce PM/PM<sub>10</sub> emissions;
- Retrofit of another type of control device (e.g., a fabric filter) would be expensive and provide little additional reduction in emissions (i.e., it would not be cost-effective).

Based on the technology in place (including the VOC scrubber) and the emissions limits that are typical for this type of technology, ADM concludes that BACT for PM/ PM<sub>10</sub> for the FBGD is a limit of 0.015 gr/dscf. This limit includes both filterable and condensable PM<sub>10</sub> fractions.

<sup>1</sup> This CO limit is that proposed in the December 2003 application based on test data and pursuant to Paragraph 39(b) of the National Consent Decree.

<sup>2</sup> This value (4.74 lb CO/hr) is equivalent to a CO emissions rate of 0.073 lb/MMBtu at a burner rate of 65 MMBtu/hr.

**Table 1-11. RBLC Data on PM/ PM<sub>10</sub> BACT Limits for Germ Dryers**

Company	RBLCID	Source	Pollutant	Technology	Limit
Grain Processing Corp	IN-0075	Germ Dryer	PM <sub>10</sub>	Wet Scrubber	0.01 gr/dscf
Cargill	NE-0016	Germ Dryer	PM	Cyclone/Wet Scrubber	0.05 lb/MMBtu
Cargill	NE-0016	Germ Dryer	PM <sub>10</sub>	Cyclone/Wet Scrubber	0.031 lb/MMBtu
Cargill	IA-0057	Germ Dryer/Cooler II	PM <sub>10</sub>	Cyclone / Scrubber	0.006 gr/dscf
Cargill	IA-0057	Germ Dryer/Cooler	PM <sub>10</sub>	Cyclone / Scrubber	0.006 gr/dscf
Cargill	IA-0029	Corn Germ Dryers & Coolers (2)	PM	Cyclone Scrubber	0.01 gr/dscf
ADM (formerly MCP)	NE-0014	Germ Dryers	PM <sub>10</sub>	Wet Scrubber	3.82 lb/hr
ADM (formerly MCP)	NE-0014	Fluidized Bed Germ Dryer #1	PM	Cyclone	0.01 gr/dscf

\* These BACT limits were based on filterable PM only. Tests on a similar GFD at ADM's Marshall, MN plant have shown that filterable PM accounts for about 2/3 of the total PM/PM<sub>10</sub> (i.e., filterable plus condensable PM/ PM<sub>10</sub>). Thus, a limit of 0.01 gr/dscf for filterable PM is equivalent to a limit of 0.015 for filterable plus condensable PM/ PM<sub>10</sub>.

#### 1.7.4 NO<sub>x</sub> Control Technology Review

NO<sub>x</sub> emissions result from the combustion of natural gas in the fluidized bed germ dryer. Generally, germ dryers fired with natural gas have relatively low NO<sub>x</sub> emissions (less than 0.10 lb NO<sub>x</sub>/MMBtu) because there is no fuel bound nitrogen in natural gas and combustion takes place in a relatively low temperature setting. To identify the types of NO<sub>x</sub> controls used for reducing emissions from similar sources, the RBLC database was searched for BACT determinations on germ dryers. Table 1-12 summarizes the results of this search. As this table shows, only combustion controls (such as low-NO<sub>x</sub> burners) have been used to control NO<sub>x</sub> from germ dryers. No add-on technologies (e.g., selective catalytic reduction) have been used.

Generally there are a number of NO<sub>x</sub> control technologies used to control NO<sub>x</sub> emissions from gas-fired combustion sources including selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and combustion controls such as low NO<sub>x</sub> burners, low excess air operation, and flue gas recirculation. However, the technical and economic feasibility of each of these control technologies are based on process factors (e.g., flue gas temperatures and contaminant loading), operating schedule, and control efficiency capability. The following subsections discuss the technical feasibility of applying SCR and SNCR controls to germ dryers. The SCR and SNCR discussion provides the technical and economic understanding as to why these technologies are not used to control NO<sub>x</sub> from such dryers.

**Table 1-12. RBLC Data on NO<sub>x</sub> BACT Limits for Germ Dryers**

RBLCID	FACILITY	PERMIT DATE	PROCESS	CTRLDESC	LIMIT (lb/MMBtu)	LIMIT (lb/hr)
NE-0014	ADM (formerly MCP)	7/12/95	Fluidized Bed Germ Dryer #1 (36.4 MMBtu/hr)	*	0.10	3.6
NE-0016	Cargill, Inc	4/25/96	Germ Dryer (50 MMBtu/hr)	No Controls Feasible	0.20	10.0
IN-0075	Grain Processing Corp.	6/10/97	Germ Dryer (16.5 MMBtu/hr)	Water quench and Low-NO <sub>x</sub> burner	0.06	1.0

\* The RBLC incorrectly lists a "spray tower" as a NO<sub>x</sub> control device for this source.

#### **1.7.4.1 SCR Technology**

The use of SCR technology is considered to be both technically and economically infeasible for application to germ dryer flue gases for the following reasons:

- The dryer exhaust gas would have to be heated from 160 °F to ~600 °F (SCR operating temperature) followed by heat recovery. This complex arrangement makes the annual cost of control unacceptably high due to the small amount of NO<sub>x</sub> that could be reduced by the addition of SCR technology; and
- The sticky, organic nature of particulate matter from this source could rapidly foul the SCR catalyst making SCR technology infeasible.

These technical and economic issues have prevented the use of SCR technology for germ dryers as demonstrated by the RBLC review. As such, SCR technology is not considered in the BACT analysis hierarchy.

#### **1.7.4.2 SNCR Technology**

The use of SNCR technology is considered to be both technically and economically infeasible for application to germ dryer flue gases for the following reasons:

- The dryer exhaust gas would have to be heated from 160 °F to about 1,600 °F (SNCR operating temperature) followed by heat recovery. This complex arrangement makes the annual cost of control unacceptably high due to the small amount of NO<sub>x</sub> that could be reduced by the addition of SNCR technology; and
- The formation of ammonium salts will cause an increase in dryer PM<sub>10</sub> emissions and opacity.

These technical and economic issues have prevented the use of SNCR technology for germ dryers as demonstrated by the RBLC review, which found no SNCR applications on such dryers. As such, SNCR technology is not considered in the BACT analysis hierarchy.

#### **1.7.4.3 NO<sub>x</sub> Control Technology Hierarchy**

The results of the technology review identified only combustion controls as being technically feasible. The RBLC search identified three NO<sub>x</sub> emission limits established between 1994 June 2004. As Table 1-12 shows, the NO<sub>x</sub> emission limits for germ dryers range from 0.06 lb/MMBtu to 0.10 lb/MMBtu based on the use of combustion control technologies. In addition, recently permitted/installed dryers at ADM corn plants typically have achieved NO<sub>x</sub> emission rates of 0.06 lb /MMBtu or lower.

#### **1.7.4.4 Proposed BACT Emission Rate for NO<sub>x</sub>**

Consistent with the identified RBLC BACT determinations, ADM proposes to use a natural gas-fired, low NO<sub>x</sub> burner with a proposed emission rate at the low end of the range found in the RBLC. Specifically, ADM proposes a 0.06 lb/MMBtu (3.3 lb NO<sub>x</sub> per hour) emission rate as the BACT limit for the Columbus FBGD.

#### **1.7.5 SO<sub>2</sub> Control Technology Review**

SO<sub>2</sub> emissions from the FBGD at the Columbus plant come from two sources. The first and primary source of SO<sub>2</sub> emissions is from dissolved SO<sub>2</sub> present in the wet germ. Drying the germ vaporizes some of the dissolved SO<sub>2</sub> as a gaseous emission. The second source of SO<sub>2</sub> is from the small amount of sulfur present in the fuel combusted in the dryer itself.

ADM reviewed the RBLC to identify SO<sub>2</sub> control technologies that have been applied as BACT for this source category. The results of this review are summarized in Table 1-13. As this table shows, the only technology being applied as BACT for this source category is wet scrubbing. Although other technologies are theoretically feasible for application to this source (e.g., dry scrubbing), since the VOC BACT determination will result in the installation of a wet scrubber for VOC control, such alternative technologies will provide little or no improvement in SO<sub>2</sub>

control, but will result in substantial added control costs. Thus, the only technology that is practical to consider for application to this source (from an economic, energy, and environmental impact perspective) is the use of wet scrubbing with caustic addition.

**Table 1-13. RBLC Data on SO<sub>2</sub> BACT Limits for Germ Dryers**

Company	RBLCID	Source	Technology	Limit(s)
Cargill	IA-0029	Corn Germ Dryers & Coolers (2)	Wet Scrubber with caustic	1.25 lb/hr
Cargill	NE-0016	Germ Dryer	No controls feasible.	0.00006 lb/MMBtu 0.03 lb/hr

Wet scrubbing with caustic addition is the top performing technology for germ dryers. ADM will install a wet scrubber on the FBGD for both VOC and SO<sub>2</sub> control. The estimated baseline SO<sub>2</sub> emissions rate for this source is 5.1 lb/hr. Assuming a 90% control efficiency for the wet scrubber, ADM proposes that BACT for the modified dryer to be based on this control efficiency and the baseline SO<sub>2</sub> emission rate of 5.1 lb/hr. Thus the new SO<sub>2</sub> BACT limit for the FBGD is proposed to be 0.51 lb/hr.

## 1.8 New Gas-Fired Package Boiler

As described in Section 2, ADM is planning on constructing a new, 250 MMBtu/hr (maximum heat input) natural gas-fired package boiler in conjunction with the alcohol plant expansion. This boiler will help meet the added steam demand created by the alcohol plant expansion as well as provide increased reliability in the Columbus plant's steam supply system. The new boiler will be a source of emissions of NO<sub>x</sub> and CO with relatively minor emissions of other pollutants. However, since this boiler is part of a larger project subject to PSD review for other pollutants, it is also subject to BACT review for those pollutants. The following discussion provides ADM's BACT review for each of the PSD pollutants that will be emitted from the new natural gas-fired boiler.

### 1.8.1 Oxides of Nitrogen Control Technology Review.

Nitrogen oxides are formed during combustion by two major mechanisms; thermal formation ("Thermal NO<sub>x</sub>"), and fuel formation ("Fuel NO<sub>x</sub>"). Thermal NO<sub>x</sub> results from the high temperature oxidation of nitrogen (N<sub>2</sub>) and oxygen (O<sub>2</sub>). In this mechanism, N<sub>2</sub> is supplied from air, which is approximately 79 percent N<sub>2</sub> by volume. As its name implies, thermal NO<sub>x</sub> formation is primarily dependent on combustion temperature. Thermal NO<sub>x</sub> formation increases exponentially with temperature, and becomes significant at temperatures above 2,800 °F. Fuel NO<sub>x</sub> results from the direct oxidation of organic nitrogen compounds in the fuel. Because natural gas contains virtually no nitrogen, NO<sub>x</sub> emissions from the combustion of natural gas are primarily from thermal formation.

#### 1.8.1.1 Identification of Technically Feasible NO<sub>x</sub> Controls

The RBLC database was reviewed to identify technologies used to control NO<sub>x</sub> emissions from gas fired industrial boilers (boilers less than 250 MMBtu/hr). The only NO<sub>x</sub> control technologies identified for industrial gas fired boilers were low NO<sub>x</sub> burners with and without flue gas recirculation. Emission limits for these boilers range from 0.035 lb NO<sub>x</sub>/MMBtu to greater than 0.10 lb NO<sub>x</sub>/MMBtu.

In addition to low NO<sub>x</sub> burners with and without flue gas recirculation, the following post-combustion NO<sub>x</sub> control technologies are commercially available for gas fired combustion sources of any heat input:

- SCONOX™;
- Non-Selective Catalytic Reduction (NSCR);
- Selective Non-Catalytic Reduction (SNCR); and
- Selective Catalytic Reduction (SCR).

#### Low-NO<sub>x</sub> Burner Technology

Low NOx burner (LNB) technology covers a wide range of burner types because there are currently three generations of burner technology in use. For purposes of presentation, the discussion of these three generations is presented as follows:

- Second generation, which was initially installed in the mid/late 1980s, is commonly referred to as a Low-NOx burner. NOx emissions achieved by this technology were generally in the range of 0.06 lb/MMBtu on new installations to 0.10 lb/MMBtu on retrofit applications.
- Next generation Low-NOx burner technology was first installed in the early to mid 1990s. The NOx emissions achieved by this technology ranged from 0.03 lb/MMBtu for new boilers to 0.05 lb/MMBtu (assuming no air preheat) for retrofit applications.
- “Next generation” Ultra Low NOx burners were first installed in the 2000/2001 timeframe. These burners have been demonstrated to achieve 0.02 lb/MMBtu while firing natural gas. The level that can be achieved depends in large part on whether the application is on a new unit versus the retrofit of an existing unit.

All three generations of LNB technology reduce the rate of NOx formation by lowering the peak and average combustion temperature. This is accomplished by staging the introduction of the air/flue gas with the fuel into two zones: a primary and secondary combustion zone. Subsequent generations of this technology have improved the mixing of air and fuel in the primary and secondary zones by either premixing the air/flue gas with the fuel prior to the burner flame or enhancing the mixing capability through the use of an increasing number of tiny fuel/air ports in the burner tip. In addition, more advanced burner designs also incorporate the use of external flue gas recirculation, which works to reduce NOx emissions because the recirculated flue gas is lean in oxygen and acts as a diluent gas to quench the flame temperature. Premixing of the fuel with flue gas and/or air also reduces the peak and average flame temperatures because the premixed air acts as a diluent while also working to reduce localized hot spots associated with extremely high NOx formation rates. As noted above, each of these designs reduces the rate of NOx formation by lowering the peak and average combustion temperatures. Low-NOx burner technology is regarded as reliable and is almost exclusively used to satisfy BACT requirements for new gas fired boilers.

### **SCONox™**

SCONox is a trade name for a proprietary NOx control technology being marketed by Goal Line Technologies, a joint venture between Sunlaw Energy Corporation and Advanced Catalyst Systems, Inc. The SCONox system uses a potassium carbonate-coated platinum catalyst to oxidize CO to CO<sub>2</sub> and reduce NOx to N<sub>2</sub> and water. The effective operating temperature for SCONox is 280 to 750°F, with 500 to 700°F being the optimum range for NOx removal. Regeneration of the NOx saturated carbonate is accomplished by passing a dilute hydrogen reducing gas across the surface of the catalyst in the absence of oxygen. The sections of the reactor catalyst being regenerated are isolated from exhaust gases using sets of louvers on the upstream and downstream side of each reactor box. Multiple catalyst reactor boxes are required with some in the oxidation/absorption cycle and some in the regeneration cycle at any given time. The catalyst beds must also be rejuvenated every six (6) months to one year by dipping them in a solution of potassium carbonate. SCONox produces approximately twice the pressure drop of SCR.

The SCONox catalyst is subject to fouling and masking degradation as a result of trace impurities either from the combustion gases or from ambient air. The SCONox bed preferentially absorbs sulfur compounds, and therefore the system is highly sensitive to sulfur concentration in the combustion gases. SO<sub>2</sub> in the combustion gas is oxidized to SO<sub>3</sub>, which reacts with the potassium carbonate to form potassium sulfate. Sulfur effectively deactivates the sorbent and regeneration produces toxic hydrogen sulfide (H<sub>2</sub>S). Where sulfur compounds are present, including even minor sulfur concentrations associated with some pipeline natural gas applications, the fuel must either be pretreated (e.g., scrubbed to remove sulfur to below a 1 ppmv level), or a second catalyst bed known as SCOSox must be placed before the SCONox bed to capture the sulfur compounds.

To date, SCONox has only been commercially demonstrated on natural gas-fired electric utility combustion turbine sources with “clean” exhaust streams (i.e., units fired with very low-sulfur pipeline quality natural gas). Such fuels have very low sulfur content, partially in the form of mercaptans (at less than 1 ppmv) used for “odorization.” This very low sulfur content results in sufficiently low SO<sub>2</sub> in the exhaust gas that can be tolerated by the SCONox catalyst. SCONox has not been demonstrated on packaged boilers, and is more costly than SCR, which is considered economically infeasible (see later discussion). As such, SCONox is not considered further in this analysis.

## Non-Selective Catalytic Reduction

NSCR is the flue gas treatment technology that is used to catalytically control NO<sub>x</sub> emissions from automobile engines and other reciprocating engines. This technology uses precious metal catalysts, such as platinum, to promote reactions between free radical hydrocarbons, produced by fuel rich combustion, and NO to produce molecular nitrogen (N<sub>2</sub>) and water. Catalyst modules are located in the exhaust duct just downstream of the combustion chamber where temperatures are sufficiently high for reaction. The major products of the reactions are molecular nitrogen, carbon dioxide, and water. Application of this technology also requires the installation of downstream oxidation catalysts to remove any unreacted products of rich combustion. Operating conditions for NSCR require rich-burn fuel to air ratios with less than about 4% oxygen present. As a result, NSCR is only applicable to combustion systems like reciprocating engines, where the combustion process can be tightly controlled in a fuel rich firing zone. Consequently, NSCR is not suitable for boilers, which operate with 4 to 8 % oxygen; it has not been demonstrated on this source type; and it is therefore considered technically infeasible. As a result, it is not considered further by this analysis.

## Selective Non-Catalytic Reduction

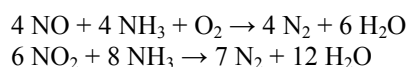
SNCR systems reduce NO<sub>x</sub> by injecting ammonia (i.e., a selective reactant) into the high-temperature regions (i.e., 1,500 to 2,000°F) of a boiler where the ammonia will selectively react with NO<sub>x</sub> to produce nitrogen and water. In addition to operating temperature requirements, good mixing and sufficient residence time (i.e., greater than 0.5 seconds) at temperature must also be present. The combined temperature and residence time requirement is the reason that this method of control is well demonstrated on large industrial and utility sized boilers. Careful temperature control is needed; if the operating temperature is too low, unreacted ammonia will pass directly through the system to the atmosphere. If the operating temperature is too high, ammonia will be oxidized to NO and more NO<sub>x</sub> will be emitted than if no controls were present. Based on the USEPA ACT document for gas fired boilers, vendors reported NO<sub>x</sub> reductions of 30 to 65% for packaged water tube boilers.<sup>1</sup>

Two SNCR processes are in commercial use today: Thermal DeNO<sub>x</sub><sup>®</sup>, developed by Exxon, is an example of technologies that use ammonia as the reducing agent, and NO<sub>x</sub>OUT<sup>®</sup> is a process that uses chemically treated urea as the reducing agent. At injection temperatures, the urea rapidly decomposes to form ammonia and other reactive reduced ammonia compounds. Chemical storage and handling facilities must be built to accommodate either of these reagents.

Both SNCR processes have an optimum temperature window of between 1,600 to 1,900°F. As the desired NO<sub>x</sub> removal efficiency is increased, the amount of ammonia slip increases due to the non-uniform distribution of reacting gases and stoichiometric ammonia to NO<sub>x</sub> ratio required to achieve higher reductions. Issues related to ammonia transport and storage, ammonia slip emissions, and the associated increase in fine particulate matter (PM<sub>10</sub>) emissions are all considerations when specifying an SNCR control system. The proposed boiler exhaust temperatures will be well below 1,500°F and flue gas temperatures in the furnace prior to the convective heat transfer sections are much greater than 2000°F. As a result, an extended location within the convective heat transfer sections of the boiler would be required in order to provide the proper temperature range region and residence time for SNCR. This option represents a complex technology transfer (large-scale boiler control technology to smaller package boilers) that has not been commercially demonstrated nor is it available when purchasing a packaged boiler. Additionally, LNB technology can achieve lower NO<sub>x</sub> emissions than can be achieved with SNCR technology. As such, SNCR is not considered a technically feasible control option and is not considered further by this analysis.

## Selective Catalytic Reduction

SCR systems use ammonia to reduce NO<sub>x</sub> emissions by injecting ammonia (NH<sub>3</sub>) into the exhaust gas stream upstream of a catalyst. Ammonia absorbed on the catalyst surface selectively reacts with NO<sub>x</sub> in the presence of oxygen to form nitrogen and water. The chemical reactions involved in the SCR process are:



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<sup>1</sup> See Table 5-12 of *Alternate Control Techniques Document—NO<sub>x</sub> Emissions from ICI Boilers*, EPA-453/R-94-022.



Catalyst performance is optimized when the oxygen level in the exhaust gas stream is above two to three percent. Commercial applications of this technology have been demonstrated over an extended temperature range from 350 to 1000°F. The catalyst material that is used defines the optimal temperature range. Precious metal catalysts can promote the reduction reactions at temperatures as low as 350° F. Base metal oxide catalysts, such as vanadium and titanium, work best in the temperature range from 550 to 800°F. Zeolite-based and some newer base metal catalysts work up to 1000°F. The removal efficiency of an SCR system in good working order is typically between 65 to 90 percent. SCR systems on packaged boilers can operate alone, but are typically used in conjunction with LNB to reduce NO<sub>x</sub> emissions to their lowest levels.

Ammonia, in the form of either liquid anhydrous ammonia or aqueous ammonium hydroxide, is stored on site and injected into the exhaust stream upstream of the catalyst. As the desired NO<sub>x</sub> removal efficiency is increased above 75 percent, the amount of ammonia slip increases due to the non-uniform distribution of reacting gases and stoichiometric ammonia to NO<sub>x</sub> ratio required to achieve higher reductions. Issues related to ammonia transport and storage, ammonia slip emissions, and the associated increase in fine particulate matter (PM<sub>10</sub>) emissions are all considerations when specifying an SCR control system.

The catalytic NO<sub>x</sub>-ammonia reaction is temperature dependant. As such, SCR is well demonstrated in base loaded combined cycle natural gas-fired turbine applications where the SCR operating temperature is well-defined. SCR is demonstrated to a lesser extent in natural gas fired packaged boiler applications where the operating temperature is not as constant. In combined cycle applications, SCR catalyst and ammonia injection grids are typically installed between the tube bundles within the heat recovery steam generator where the flue gas temperature remains within the required temperature range during base load operation. Automatic controls are used to cut back ammonia feed when the catalyst bed is below the set point temperature (e.g., during startup, shutdown, and partial load operation). A similar approach will be necessary in packaged boiler applications but the load operation and corresponding flue gas temperatures are likely to be much more variable.

#### 1.8.1.2 NO<sub>x</sub> Control Hierarchy

The proposed package boiler will be subject to the standards of performance for new stationary sources under 40 CFR Part 60, Subpart Db, "Industrial-Commercial-Institutional steam generating units." For a new source, BACT requires, at a minimum, meeting these performance standards. The Subpart Db NO<sub>x</sub> emission limitation for the proposed boiler depends on the heat release rate (which has not yet been determined). Based on the above discussion, the technically feasible NO<sub>x</sub> controls identified for further evaluation as part of this BACT analysis are SCR and low NO<sub>x</sub> burners (with and without FGR). A review of the RBLC database, state BACT databases, and other available data was next conducted to determine the emissions limits resulting from previous BACT determinations for gas fired boilers. The results of this effort are summarized in Table 1-14, which presents a summary of most stringent NO<sub>x</sub> emissions limitations identified.

**Table 1-14. Most Restrictive NO<sub>x</sub> Limits**

Facility Name (permit date)	Process Description	Control Strategy	Limit (calculated)	Basis
Darling International (7/7/90 permit date)	110 MMBtu/hr natural gas-fired Nebraska water-tube boiler used to provide steam. Propane use as backup fuel.	Coen Low NO <sub>x</sub> Burner with FGR and SCR	9 ppmvd @ 3% O <sub>2</sub> (0.011 lb/MMBtu), Ammonia slip limit is 20 ppmvd @ 3% O <sub>2</sub>	South Coast AQMD
CON AGRA SOYBEAN PROCESSING CO. (8/14/1998)	200 MMBtu/hr Boiler	LOW NO <sub>x</sub> BURNERS AND FLUE GAS RECIRCULATION	0.035 lb/MMBtu	PSD Avoidance

**Table 1-14. Most Restrictive NO<sub>x</sub> Limits (Continued)**

Facility Name (permit date)	Process Description	Control Strategy	Limit (calculated)	Basis
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Helm Concentrates (5/1/90)	130 MMBtu/hr gas-fired Cleaver-Brooks model # DL DH-102 water-tube boiler producing 100,000 lb steam/hr; propane and butane backup fuels	Todd Variflame Low NOx Burners with FGR	30 ppmvd @ 3% O2 (0.036 lb/MMBtu)	San Joaquin Valley Unified APCD
San Benito Food Tomato Processing (12/14/98)	210 MMBtu/hr natural gas-fired Cleaver Brooks boiler with Todd combustion variflame burner	Low NOx burner and flue gas recirculation	30 ppmvd @ 3% O2 (0.036 lb/MMBtu)	Monterey Bay Unified APCD
CARGILL- EDDYVILLE (4/22/1999)	182.1 MMBtu/hr Boiler	LOW NOX BURNERS WITH FGR	0.05 lb/MMBtu	PSD avoidance
ALABAMA POWER COMPANY - THEODORE COGENERATION (3/16/1999)	220 MMBtu/hr Boiler	LNB AND FLUE GAS RECIRCULATION	0.053 lb/MMBtu	BACT-PSD
ARCHER DANIELS MIDLAND CO. - NORTHERN SUN VEG. OIL (7/9/1998)	189 MMBtu/hr Boiler		0.053 lb/MMBtu	BACT-PSD
OKEELANTA CORPORATION SUGAR MILL (10/29/2001)	211 MMBtu/hr Boiler	LOW NOX BURNERS W/FLUE GAS RECIRCULATION AND GOOD COMBUSTION.	0.06 lb/MMBtu	BACT-PSD
WILLIAMS REFINING & MARKETING, L.L.C. (4/3/2002)	180 MMBtu/hr Boiler		0.06 lb/MMBtu	BACT-PSD

Based on the previous technology discussions, the NO<sub>x</sub> BACT hierarchy is as follows:

Control Option	Percent Control verses Combustion Control	NO <sub>x</sub> Emission Rate lb/MMBtu
CC+LNB+SCR	96	0.004
CC+ advanced LNB	82	0.018
CC+LNB	64	0.036
Combustion Control (CC)	0	0.100

#### 1.8.1.3 Impacts Analyses for NO<sub>x</sub> Controls

Table 1-15 presents the impacts of three levels of NO<sub>x</sub> control using LNB and SCR technology.

**Table 1-15. NOx BACT Economic, Energy, and Environmental Impacts**

Parameter	Good Combustion Control	Good Combustion Control + Low-NOx Burners	Good Combustion Control + Advanced Low-NOx Burners	Good Combustion Control + Low-NOx Burners + Selective Catalytic Reduction
<b>Environmental Impacts:</b>				
NOx Emitted, lb/MMBtu	0.1	0.036	0.018	0.004
NOx Emitted, lb/hr	24.9	9.0	4.5	0.9
NOx Emitted, TPY	109.1	39.3	19.6	3.9
NOx Reduced, TPY	Baseline	69.8	89.4	105.1
% Control	Baseline	64%	82%	96%
Secondary Emissions	Baseline	Increased CO Emissions	Increased CO Emissions	Increased CO, NH <sub>3</sub> , and PM/ PM <sub>10</sub>
<b>Energy Impacts:</b>				
kW-hr/yr Power	Baseline	247,713	371,570	761,819
<b>Economic Impacts:</b>				
Total Capital Cost	Baseline	\$39,658	\$416,762	\$1,620,088
Total Annual Cost	Baseline	\$51,438	\$129,637	\$464,220
<b>Cost Effectiveness Results</b>				
Absolute @ 100% Capacity Factor	Baseline	\$737	\$1,450	\$4,415
Cost Effectiveness vs LNB @ 100% Capacity Factor	Not applicable	Not applicable	\$3,983	\$11,682
Cost Effectiveness vs LNB @ 60% Capacity Factor	Not applicable	Not applicable	\$6,638	\$13,022
Cost Effectiveness vs ALNB	Not applicable	Not applicable	Not applicable	\$21,304

#### 1.8.1.4 Proposed BACT Limit for NOx Emissions

Based on the above analysis, ADM proposes LNB control with an emission limit of 0.036 lb/MMBtu as BACT. The BACT emission rate selection rationale follows:

SCR is considered economically infeasible for the proposed gas fired boiler at the Columbus facility due to:

- The incremental increase in annual costs of \$412,782 and cost effectiveness of \$11,682 per ton of additional NOx emissions reduced relative to LNB is excessive; and
- The capital cost of \$1.6 million is an increase in the boiler project capital costs of 40 percent, and is excessive for a maximum NOx reduction of 34 tons per year relative to LNB.

Advanced LNB control is considered economically infeasible for the proposed gas fired boiler due to:

- The incremental cost effectiveness of \$3,983 per ton (100% capacity factor) to \$6638 per ton (60 percent capacity factor) is excessive; and

- The capital cost of \$539,784 and annual cost of \$138,083 is excessive for a maximum NO<sub>x</sub> reduction of 19 tons per year relative to LNB.

Based on the above analysis, ADM proposes a NO<sub>x</sub> BACT limit of 9.0 lb/hr based on an emission rate of 0.036 lb/MMBtu.

## **1.8.2 Sulfur Dioxide and Sulfuric Acid Mist (H<sub>2</sub>SO<sub>4</sub>)**

Emissions of SO<sub>2</sub> result from the oxidation of fuel sulfur. During combustion, the majority of the fuel sulfur is emitted as SO<sub>2</sub>. A portion of the fuel sulfur is further oxidized to SO<sub>3</sub>. Sulfur trioxide is then readily converted in the flue gas or in the atmosphere to H<sub>2</sub>SO<sub>4</sub> as the gas temperature drops. Natural gas is treated by the supplier to very low levels of sulfur compounds resulting in a typical emission factor of 0.006 lb SO<sub>2</sub>/MMBtu with H<sub>2</sub>SO<sub>4</sub> emissions typically being 1 to 2 percent of the SO<sub>2</sub> emissions.

### **1.8.2.1 Identification of Technically Feasible Controls**

The RBLC database was reviewed to identify the technologies used to control SO<sub>2</sub> and H<sub>2</sub>SO<sub>4</sub> from gas fired boilers. The use of natural gas (fuel specification) is the only control identified. RBLC database emission limits for natural gas fired boilers range from 0.0006 to 0.20 lb SO<sub>2</sub>/MMBtu. No H<sub>2</sub>SO<sub>4</sub> emission limits were found in the RBLC database for gas fired industrial boilers. Although other technologies are available for the control of SO<sub>2</sub> and H<sub>2</sub>SO<sub>4</sub>, such as wet and dry flue gas desulfurization, these other technologies would not be economically feasible for the control of 1 ton per year of SO<sub>2</sub> and 0.01 tons per year of H<sub>2</sub>SO<sub>4</sub>.

### **1.8.2.2 Proposed BACT Limit for SO<sub>2</sub> and H<sub>2</sub>SO<sub>4</sub>**

Based on the above analysis, ADM proposes the use of natural gas for SO<sub>2</sub> and H<sub>2</sub>SO<sub>4</sub> emission control as BACT.

## **1.8.3 Particulate Matter Control Technology Review**

This control technology review includes a BACT analysis for the control of PM and PM<sub>10</sub>. For gas-fired boilers, emissions of PM and PM<sub>10</sub> result primarily from incomplete combustion.

### **1.8.3.1 Identification of Technically Feasible Controls**

Natural gas combustion results in the lowest PM and PM<sub>10</sub> emissions when fired with good combustion practices resulting in a typical PM/ PM<sub>10</sub> emission factor of 0.0076 lb/MMBtu. The RBLC database was reviewed to identify the technologies used to control PM and PM<sub>10</sub> from gas fired boilers. The use of natural gas (fuel specification) is the only control identified. RBLC database emission limits for natural gas fired boilers range from 0.005 to 0.020 lb PM<sub>10</sub>/MMBtu. Although other technologies are available for the control of PM and PM<sub>10</sub>, such as fabric filters and electrostatic precipitators, these other technologies would not be economically feasible for the control of the 11 ton per year of PM and PM<sub>10</sub> estimated to be emitted from the new boiler.

### **1.8.3.2 Proposed BACT Limits for PM and PM<sub>10</sub>**

Based on the above analysis, ADM proposes the use of natural gas for PM and PM<sub>10</sub> emission control as BACT.

## **1.8.4 CO and VOC Control Technology Review.**

CO and VOC are emitted from natural gas fired boilers as a result of incomplete fuel combustion. This chapter includes a review of CO and VOC emission controls and limitations applied to other similar units.

### **1.8.4.1 Identification of Technically Feasible Controls**

The technologies used to control CO and VOC emissions from natural gas boilers were first reviewed using the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC) database. The RBLC database shows that good combustion

control as the only control technology that has been applied for the control of CO and VOC emissions. Natural gas combustion results in low CO and VOC emissions when fired with good combustion practices resulting in a typical emission factor of 0.084 lb CO/MMBtu and 0.0055 lb VOC/MMBtu. The range in emission limitations from the RBLC is 0.036 to 0.165 lb/MMBtu for CO and 0.004 to 0.032 lb/MMBtu for VOC.

The only other technology capable of reducing CO and VOC emission rates below those obtained through good combustion control is an oxidation catalyst. However, while oxidation catalysts have been used to reduce CO and VOC emissions from natural gas and oil-fired combustion turbines, oxidation catalysts have not been used for natural gas fired packaged boiler applications. This is because the proposed boiler exhaust temperatures will be well below 400°F and flue gas temperatures in the furnace prior to the convective heat transfer sections are much greater than 2000°F. As a result, a location within the convective heat transfer section of the boiler would be required in order to provide the proper temperature region and residence time for the oxidation catalyst. This has not been commercially demonstrated nor is it available as a standard option when purchasing a packaged boiler.

#### **1.8.4.2 Control Technology Description and Control Hierarchy**

##### **Oxidation Catalysts**

Oxidation catalysts have been used to reduce CO and VOC emissions as a post combustion control system on gas-fired combustion turbines. The typical oxidation catalyst for CO is a rhodium or platinum (noble metal) catalyst on an alumina support material. This catalyst is installed in an enlarged duct or reactor with flue gas inlet and outlet distribution plates. Acceptable catalyst operating temperatures range from 400 - 1250 °F, with the optimum temperature range being 850 - 1,100 °F. Below 600°F, a greater catalyst volume would be required to achieve the same reduction. Typical oxidation catalyst control efficiencies for CO and VOC are 50 to 90 percent and 25 to 50 percent, respectively.

The proposed boiler exhaust temperatures will be well below 400°F and flue gas temperatures in the furnace prior to the convective heat transfer sections are much greater than 1250°F. As a result, a suitable location within the convective heat transfer sections of the boiler would be required in order to provide the proper temperature range and residence time for the oxidation catalyst. Such a location does not exist in current gas-fired package boiler designs. Thus, this option represents a complex technology transfer effort (large-scale combustion turbine control technology to a smaller gas flow from a package boiler) that has not been commercially demonstrated, nor is it available when purchasing a packaged boiler.

##### **Good Combustion Control**

Good combustion generally requires the following:

- High Temperatures;
- Sufficient Excess Air;
- Sufficient Residence Times; and
- Good Air/Fuel Mixing.

As with other types of fossil fuel-fired boilers, combustion control is the most effective means for reducing CO and VOC emissions from natural gas fired boilers. Combustion efficiency is often related to the three “T’s” of combustion: Time, Temperature, and Turbulence. These components of combustion efficiency are designed into the boiler to maximize fuel efficiency and reduce operating costs. Therefore, combustion control is accomplished primarily through boiler design and operation.

Changes in excess air affect the availability of oxygen and combustion efficiency. Very low or very high excess air levels will result in high CO and VOC formation, and can also affect NOx formation. Increased excess air levels will reduce the emissions of CO and VOCs up to the point that so much excess air is introduced that the overall combustion temperatures begin to drop significantly. If combustion temperatures drop significantly, then boiler efficiency and steam temperatures are also negatively affected.

Based on the above review, good combustion control is the only technically feasible control options for CO and VOC.

#### 1.8.4.3 Proposed BACT Limit for VOC Emissions

Based on the information presented above, ADM proposes good combustion control as BACT for VOC emissions. Based on review of VOC emission limitations currently established for similar facilities, ADM proposes a boiler BACT limitation of 1.4 pounds per hour for a 3-hour block average. This limit is equal to a VOC emission rate of 0.0055 lb/MMBtu, and would apply at all times and all loads other than during startup, shutdown, and malfunction conditions. This limit is consistent with the most recent BACT VOC emission limits found in RBLC, which range from 0.0036 to 0.032 lb/MMBtu.

#### 1.8.4.4 Proposed BACT Limit for CO Emissions

Based on the information presented above, ADM proposes good combustion control as BACT for CO emissions. Based on our review of CO emission limitations currently established for similar facilities, ADM proposes a BACT limitation of 23.6 pounds per hour for a 30-day rolling average. This limit is equal to a full load CO emission rate of 0.0945 lb/MMBtu, and would apply at all times and all loads other than during startup, shutdown, and malfunction conditions. This limit is consistent with the most recent BACT CO emission limits found in RBLC, which range from 0.036 to 0.165 lb/MMBtu. A 30-day rolling averaging time using a CO continuous monitor is proposed to account for load changes and associated process adjustments to remain in compliance with NO<sub>x</sub> emission limits.

#### 1.8.5 Boiler MACT and BACT for HAPs

The proposed gas-fired boiler will emit small quantities of hazardous air pollutants (HAPs). The potential HAP emissions from the proposed boiler are summarized below:

Hazardous Air Pollutant	Potential Emissions (tpy)	Emission Basis
Organic HAPs <sup>1, 2</sup>	6.5	MACT compliance
Metals <sup>3</sup>	< 0.1	Natural Gas Combustion Only

This section addresses the control of HAP emissions relative to:

- The recently promulgated National Emissions Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters<sup>4</sup>; and
- BACT for HAPs as prescribed by N.A.C. Title 128, Chapter 27.

The USEPA has promulgated maximum achievable control technology (MACT) emission limits and standards for industrial boilers, such as the proposed natural gas fired boiler. The proposed boiler meets the MACT applicability classification as a New, Gaseous Fuel, Large Unit. As such, the proposed boiler must comply with the MACT limits and standards upon startup.

BACT for HAPs is a requirement of the Nebraska Administrative Code pursuant to Title 129 Chapter 27. In this case, the BACT limit is determined on a case-by-case basis. Additionally, pursuant to the U.S. EPA Administrator's

<sup>1</sup> Sum of organic HAPs identified in AP-42 Table 1.4-3:  
(i.e., 6.5 tons/yr = (6.1 lb/10<sup>6</sup>scf) / (1020 Btu/scf) x (250 MMBtu/hr) x (8760 hr/yr) / (2000 lb/ton))

<sup>2</sup> For purposes of this analysis, HAP refers to those compounds identified in N.A.C. Title 129, Appendix II.

<sup>3</sup> Sum of inorganic HAP identified in AP-42 Table 1.4-4:  
(i.e., 0.045 tons/yr = (0.042 lb/10<sup>6</sup>scf) / (1020 Btu/scf) x (250 MMBtu/hr) x (8760 hr/yr) / (2000 lb/ton))

<sup>4</sup> Also, referred to as Maximum Achievable Control Technology or MACT standards.

decision in the North County Resource Recovery Associates, PSD Appeal No. 85-2, a PSD permitting authority (NDEQ) should consider the effects of a control alternative on toxic or hazardous pollutants. The ability of a given control alternative to control HAP emissions must be evaluated and HAP emissions resulting from the given control technology should be considered in making the BACT decision.

Based on economic feasibility, ADM proposes minimization of the federally regulated HAPs through the use of combustion control, and exclusive use of natural gas as fuel consistent with the proposed PSD-BACT decisions for CO, VOC, and PM and consistent with the Industrial Boiler MACT standard. The following paragraphs describe the BACT/MACT limits and standards for trace element HAPs (arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium compounds), and organic HAPs.

Trace element HAP emissions may be emitted from the boiler. The best and simplest method of control of trace element HAPs is the use of low-ash fuels. The use of natural gas as the fuel results in the minimum emissions of trace element HAPs as compared to any other fossil fuel. As a result, the MACT standard does not require the control of trace element compounds for gaseous fuel boilers. Trace organic HAP emissions may be emitted from the boiler as a result of incomplete combustion. The best and simplest method of control of organic HAPs is the destruction of these compounds by incineration or combustion. High temperatures, an optimum amount of oxygen, and good mixing of the components involved are needed to ensure the destruction of organics. However, greater control of organics through higher furnace combustion temperatures would be at the expense of increased emissions of other pollutants (i.e., NO<sub>x</sub>). The proposed MACT limit for these compounds uses CO as a surrogate. This limit is 400 ppm CO at 3% oxygen monitored continuously.<sup>1</sup> Note that ADM's proposed PSD-BACT limit for CO is equivalent to about 92 ppmv.

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<sup>1</sup> The MACT for organic HAPs is good combustion control. Good combustion control is defined by having less than 400 ppm CO in the boiler flue gases.

## **Appendix C - PSD-BACT Analysis for Starch Dryer #2 Project**



## 1. Best Available Control Technology (BACT) Review for the Starch Dryer #2 Construction Project

Title 129, Chapter 19 of the Nebraska Administrative Code (N.A.C.) adopts the requirements of 40 CFR 52.21 (as amended through July 1, 1997) by reference. As discussed in Sections 2 and 3 of this application, ADM has determined that adjustment of the corn processing limit to 240,000 bushels per day and the removal of the simultaneous loading restriction on Starch Storage Bins #13 and #14 requires that ADM apply current BACT to the sources that were constructed or modified as part of the Starch Dryer #2 construction project (i.e., those sources installed or modified pursuant to the December 23, 1999 construction permit). These sources are listed in Table 1-1.

**Table 1-1. Sources Constructed or Modified Pursuant to the Starch Dryer #2 Construction Permit**

Source	EU#	Control Equipment
Starch Dryer #2 (steam heated dryer)	SV-45	Cyclones/ Wet Scrubber
Starch Storage Bin #13	SV-46	Fabric Filter
Starch Storage Bin #14	SV-47	Fabric Filter
Starch Transport/Loadout Receiver	SV-48	Fabric Filter
Off-Spec Starch Receiver	SV-22	Fabric Filter

ADM has used a “top-down” approach to evaluate BACT for each of these sources. As described in Section 4 of this application, the top-down BACT approach identifies and ranks feasible control technologies based on their effectiveness in reducing emissions. If the most effective technology is accepted as BACT, the analysis stops. However the most effective technology is often evaluated to determine economic, energy, and environmental impacts. If these impacts are unacceptable, the top technology is rejected as BACT and the next best performing technology is evaluated. This process continues until an acceptable BACT technology is identified.

The remainder of this appendix provides a BACT analysis for each of the sources listed in Table 1-1. Sources with similar emissions characteristics and control options are grouped together for discussion purposes.

### 1.1 Starch Dryer #2

Starch Dryer #2 was installed pursuant to the December 23, 1999 construction permit application. This dryer is equipped with cyclones followed by a wet scrubber for control of particulate emissions. Since the dryer is steam heated, no emissions other than particulate matter (PM and PM<sub>10</sub>) are expected.

ADM reviewed the RBLC for information on control technologies for the starch dryer. Only one starch dryer was found in the RBLC.<sup>1</sup> This dryer employs a water scrubber and has a PM<sub>10</sub> emissions limit of 0.01 grain/dscf. Wet scrubbers are the control device of choice for starch dryers because of the humid nature of the starch dryer exhaust and the generally large size of starch particles, which makes collection using wet scrubbers quite effective. Although other PM control technologies might be considered for application to a starch dryer (e.g., a baghouse), technical and/or cost issues relative to any enhanced performance are such that other options are not considered feasible.

For example, ADM reviewed the RBLC and determined that BACT emission limits for baghouse controlled exhaust streams in the grain processing industry typically range from 0.001 to 0.01 grains/DSCF with an average BACT

<sup>1</sup> Grain Processing Corporation, Washington, IN, Permit No. CP 027-7239-00046, June 1997.

limit of approximately 0.005 gr/dscf (see Appendix D for a sampling of the RBLC search results) . Thus, the current Starch Dryer #2 limit of 0.00438 grains/DSCF is consistent with a BACT limit that would be expected from application of baghouse technology.<sup>1</sup> Based on this assessment, ADM concludes that the currently installed cyclone/wet scrubber technology represents the top performing technology for purposes of assessing BACT. Further, through source testing, ADM has demonstrated that the existing PM<sub>10</sub> emissions limit for Starch Dryer #2 (*i.e.*, 3.03 lb/hr and 0.00438 grains/DSCF) is achievable. ADM therefore concludes that BACT for Starch Dryer #2 is the use of the existing cyclone/wet scrubber system to achieve the current PM<sub>10</sub> emissions limits.

## 1.2 Dry Starch Storage and Handling

The dry starch production from Starch Dryer #2 is pneumatically transferred to one of two product storage bins and from there is loaded to railcars. Off-specification starch is sent to a third bin. As part of the 1999 Starch Dryer #2 construction project, four emissions sources were either constructed or modified. These sources are listed in Table 1-2. As Table 1-2 shows, each of these sources is equipped with a baghouse for control of particulate emissions from the starch handling, storage, and loadout operations. Based on ADM's review of the RBLC for dry starch sources (*i.e.*, loadout, blending, and storage), BACT for these sources is the use of a fabric filter/baghouse with an emissions limit of 0.005 grains/DSCF (Table 1-2). This result is also consistent with the general conclusion reached from reviewing grain industry sources as described in Section 1.1. For these reasons, ADM concludes that the top performing technology and BACT for the dry starch handling and storage sources listed in Table 1-2 is the use of a fabric filter to achieve an emissions limit of 0.005 grains/DSCF. The mass emission limits corresponding to this rate are listed in Table 1-3.

**Table 1-2.**  
**RBLC BACT Technologies and Limits for Dry Starch Sources (post-1993 permits)**

Company / Location	Source	Technology	PM <sub>10</sub> Limit (GR/DSCF)
Grain Processing Corp. / Washington, IN	Starch Loading	Baghouse	0.005
	Starch Blending Bins	Baghouse	0.005
	Starch Loadout Screen, Conveying and Rail Loadout	Baghouse	0.005

**Table 1-3.**  
**Proposed BACT PM<sub>10</sub> Mass Emission Limits for Dry Starch Sources**

Source	ID#	Mass Limit (lb/hr)
Starch Storage Bin #13	SV-46	0.062
Starch Storage Bin #14	SV-47	0.062
Starch Transport/Loadout Receiver	SV-48	0.117
Off-Spec Starch Receiver	SV-22	0.063

<sup>1</sup> This assumes a baghouse could be applied to a starch dryer exhaust, but due to the humid nature of the exhaust gas stream combined with the properties of the starch particles, baghouse technology cannot be readily applied to this stream (*i.e.*, a baghouse is not a technically feasible control option for a starch dryer exhaust).

## **Appendix D - PSD-BACT and HAP-BACT Analysis for the CFB Boilers and support facilities**

## **1.0 BACT REVIEW FOR CIRCULATING FLUIDIZED BOILERS (CFBS) AND SUPPORT EQUIPMENT**

### **1.1 Oxides of Nitrogen Control Technology Review**

Nitrogen oxides are formed during combustion by two major mechanisms; thermal formation (“Thermal NO<sub>x</sub>”), and fuel formation (“Fuel NO<sub>x</sub>”). Thermal NO<sub>x</sub> results from the high temperature oxidation of nitrogen (N<sub>2</sub>). In this mechanism, N<sub>2</sub> is supplied from air, which is approximately 79 percent N<sub>2</sub> by volume. As its name implies, thermal NO<sub>x</sub> formation is primarily dependent on combustion temperature. Thermal NO<sub>x</sub> formation increases exponentially with temperature, and becomes significant at temperatures above 2,800 °F. Fuel NO<sub>x</sub> results from the direct oxidation of organic nitrogen compounds in the fuel. As a result, nitrogen levels in fuel have a significant impact on NO<sub>x</sub> formation.

As a result of the low temperatures at which fluidized bed boilers operate, thermal NO<sub>x</sub> makes only a minor contribution to overall NO<sub>x</sub> emissions. CFBs also suppress the formation of fuel NO<sub>x</sub> through the use of staged combustion. This is accomplished by putting less than the theoretical amount of combustion air through the air distributor plate at the bottom of the furnace and adding the remainder of the air required for good combustion in the mid to upper portion of the furnace. As a result, some of the fuel nitrogen compounds decompose into molecular nitrogen (N<sub>2</sub>) rather than forming NO<sub>x</sub>.

Nitrogen found in fuels such as coal, is typically bound to the fuel as part of the organic compounds. During combustion, the nitrogen is released as a free radical to ultimately form NO<sub>x</sub> or N<sub>2</sub>. Although it is a major factor in the NO<sub>x</sub> emission rate, only 20 to 30 percent of the fuel bound nitrogen is converted to NO<sub>x</sub>. The majority of NO<sub>x</sub> formed from fuel bound nitrogen occurs through one of two pathways. The first pathway involves the oxidation of volatile nitrogen species during the initial phases of combustion. During release, and prior to oxidation of the volatile compounds, nitrogen reacts to form several intermediate compounds in the fuel rich combustion zone (lower furnace area). These intermediate compounds are then oxidized to NO<sub>x</sub> or N<sub>2</sub> in fuel lean combustion zone (upper furnace area). It is estimated that this volatile release mechanism accounts for 60 to 90 percent of the fuel NO<sub>x</sub> contribution. The second pathway involves the release of nitrogen radicals during combustion of the char fraction of the fuel (fuel remaining after volatiles have been released). These reactions occur much more slowly than the reactions involving the volatile species.

The development of fluidized bed boiler technology has been driven largely by the need to reduce SO<sub>2</sub> and NO<sub>x</sub> emissions from the combustion of coal and high-sulfur solid fuels. The major advantages to the fluidized bed boiler technology are the ability of controlling emissions of NO<sub>x</sub> to low levels “in-situ” without post-combustion air pollution control systems, and the ability to process a wide range of solid fuels without modifications. The fluidized bed boiler combusts solid fuel(s) in a fluid bed mixture of fuel, char, ash, and other materials (limestone or sand) used to provide the desired bed characteristics. Combustion air forced in at the bottom of the furnace keeps the bed mixture in a constantly upward moving fluid flow. Combustion takes place within the furnace at low combustion temperatures ranging from 1,500 to 1,650°F. Because thermal NO<sub>x</sub> formation increases significantly in a high-temperature process with temperatures in excess of 2,000°F, the lower combustion operating temperatures of CFBs significantly reduces NO<sub>x</sub> production.

The type of fluidized bed boiler proposed for this project is the CFB boiler. CFB boilers have high fluidizing air velocities ranging from 10 to 20 ft/sec, lack a distinct transition from the dense bed at the bottom of the furnace to the dilute zone above, and have very high flow rate of re-circulated solids. The high fluidizing air velocity results in a *turbulent* fluidized bed and a high rate of entrained solids carried out of the boiler. These solids are separated from the combustion gases and returned to the furnace to improve combustion efficiency and limestone utilization. CFB boilers use combustion controls (over-fire-air and low excess air) to minimize the generation of NO<sub>x</sub>.

#### **1.1.1 Identification of Technically Feasible Controls**

The RACT/BACT/LAER Clearinghouse (RBLC) database was reviewed to identify technologies used to control NO<sub>x</sub> emissions from fluidized bed boilers. Data from the RBLC for CFB coal-fired boilers are summarized in Table 1-1. This data indicates that combustion control and/or SNCR technologies are used to control NO<sub>x</sub> emissions

from fluidized bed boilers. A broader review of the RBLC database identified low NO<sub>x</sub> burners and selective catalytic reduction (SCR) technologies for the control of NO<sub>x</sub> emissions from other types of coal-fired boilers.

The proposed CFB boilers will be subject to the standards of performance for new stationary sources under 40 CFR Part 60, Subpart Db, "Industrial-Commercial-Institutional steam generating units." BACT requires, at a minimum, meeting these performance standards. The Subpart Db NO<sub>x</sub> emission limitation for the proposed boilers is 0.2 lb/MMBtu.

### 1.1.2 Selective Catalytic Reduction (SCR)

SCR is a flue gas treatment technique for controlling NO<sub>x</sub> that can reduce emissions by 50 to 90 percent. SCR uses an ammonia (NH<sub>3</sub>) injection system and a catalytic reactor. Conventional SCR catalysts used to treat coal combustion flue gases operate in the temperature window of 600°F to 900°F. An SCR system utilizes an injection grid, which disperses NH<sub>3</sub> in the flue gas upstream of the catalyst. NH<sub>3</sub> reacts with NO<sub>x</sub> in the presence of the catalyst to form nitrogen (gas) and water according to the following general equations:



**Table 1-1.**  
**Emission Limits and Controls for NO<sub>x</sub> Identified in**  
**Recent BACT Determinations for CFB Boilers**

Company/Facility	RBLC ID <sup>a</sup>	Permit Date	NO <sub>x</sub> Limit	Control
AES Beaver Valley	IN	11/21/01	0.15 lb/MMBtu	SNCR
Enviropower	Benton, IL	07/03/01	0.125 lb/MMBtu	Not listed
Reliant Energy, Seward Power Plant	IN	06/08/01	0.15 lb/MMBtu	SNCR
Kentucky Mountain Power, LLC	Ary, KY	05/04/01	0.07 lb/MMBtu	SNCR
JEA Northside Generating Station	FL-0178	7/14/1999	0.09 lb/MMBtu (30-day rolling average)	SNCR
ADM/ Decatur Units 9 & 10	IL-0060	12/24/1998	0.12 lb/MMBtu	SNCR applied to CFB Boiler
ADM/Cedar Rapids Unit 5	IA-0046	6/30/1998	0.07 lb/MMBtu (30-day rolling average)	SNCR
ADM/Cedar Rapids Unit 6	IA-0051	6/30/1998	0.07 lb/MMBtu (30-day rolling average)	SNCR
Toledo Edison Co. - Bayshore Plant	OH-0231	6/20/1997	0.2 lb/MMBtu	Limestone Fluidized Bed
York County Energy Partners	PA-0132	7/25/1995	0.125 lb/MMBtu	SNCR
Northampton Generating Co.	PA-0134	4/14/1995	0.1 lb/MMBtu	Thermal DeNO <sub>x</sub> (SNCR)
Westwood Energy Properties, Inc.	PA-0124	12/27/1994	0.3 lb/MMBtu	Reduction in Permitted Baseline Taken

**Table 1-2.**  
**Emission Limits and Controls for NO<sub>x</sub> Identified in**  
**Recent BACT Determinations for CFB Boilers**

Company/Facility	RBLC ID <sup>a</sup>	Permit Date	NO <sub>x</sub> Limit	Control
Gilberton Power Company	PA-0110	12/20/1994	0.3 lb/MMBtu	Reduction in Permitted Baseline Taken
ADM/Decatur Units 7 & 8	IL-0058	8/11/1994	0.12 lb/MMBtu	SNCR applied to CFB Boiler
AES Warrior Run, Inc.	MD-0022	6/3/1994	0.1 lb/MMBtu	Thermal DeNO <sub>x</sub> (SNCR)
Fort Drum HTW Cogen Facility	NY-0070	3/1/1994	0.6 lb/MMBtu	No Control
ADM/Cedar Rapids Unit 4	IA-0025	8/3/1993	0.07 lb/MMBtu (30-day average)	SNCR
North Branch Energy Partners LP	PA-0058	1/25/1993	0.15 lb/MMBtu	NH <sub>3</sub> /Urea Injection (SNCR)
a- Projects listed by town/state provided by TNRC.				

For a CFB boiler, the SCR system would have to be located between the last convective section and the economizer, where optimum temperatures are present. Proper placement of the catalyst increases the cost of the boiler because the convective heat transfer area has to be divided. SCR also affects the overall plant operation, because NH<sub>3</sub> and SO<sub>3</sub> in the flue gas react to form ammonium sulfate and bisulfate upstream of other environmental controls and flue gas handling equipment. Ammonium salt deposition could damage these controls and equipment. Additionally, because the SCR system is located upstream of the economizer and air heater, any changes in boiler operations, such as increased load or excess air, will alter flue gas temperatures at the catalyst bed and can significantly affect SCR performance. Important operating and design factors associated with SCR include catalyst deactivation, problems with unreacted SO<sub>3</sub> and NH<sub>3</sub>, and process control limitations.

Catalyst deactivation is the loss of active catalyst sites necessary to promote the NH<sub>3</sub>/NO<sub>x</sub> reaction. Catalyst deactivation primarily occurs via four mechanisms -- poisoning, fouling, thermal degradation, and mechanical losses (i.e., erosion). Because the SCR system is located upstream of the baghouse, mechanical losses and fouling have the potential to be significant problems with catalyst life due to the high dust/particulate load in the flue gas. Permanent catalyst poisoning results from metals and trace elements (e.g., Na, K, and As) in coal. These elements will react irreversibly with the active acid sites on the SCR catalyst surface, thus poisoning the catalyst. Testing of a vanadium/titanium SCR catalyst, which is the predominant catalyst type used in Germany and Japan, showed that alkali metals (i.e., Li, Na, K, Rb, and Cs) are strong catalyst poisons.<sup>1</sup> The poisoning effect increases with metal basicity (i.e., K is a stronger poison than Na). U.S. Powder River Basin (PRB) coals have high alkali metal contents. CaO is also a catalyst poison because it is a strong base and chemically reacts with the SCR catalyst acid sites. The ash material from CFB boilers using limestone injection for SO<sub>2</sub> control typically contains 20 to 30 percent CaO. The high alkali metal and calcium content of CFB boiler ash is the major reason that SCR emission control technology has not been applied to CFB boilers using limestone injection. Therefore, SCR is considered technically infeasible for the proposed CFB boiler and the environmental, energy, and economic impacts of this technology were not assessed.

<sup>1</sup> Chen, J.P., Buzanowski, M.A., Yang, R.T., and Chichanowicz, J.E. 1990. Deactivation of the Vanadia Catalyst in the Selective Catalytic Reduction Process. Journal Air Waste Management Association 40:1403-1409 (1990).

### 1.1.3 Selective Non-Catalytic Reduction

SNCR is a post-combustion process for NO<sub>x</sub> control that can reduce NO<sub>x</sub> emission by 30 to 70 percent. Current SNCR technologies consist of a reagent injection system, which uses NH<sub>3</sub> or urea<sup>1</sup>. The overall reactions reduce NO<sub>x</sub> to nitrogen and water vapor and are similar to the SCR reactions described above. However, in contrast with SCR, SNCR involves the injection of NH<sub>3</sub> into high-temperature regions of the boiler to reduce NO<sub>x</sub> without the use of a catalyst. A catalyst is not necessary to support the reaction of NH<sub>3</sub> and NO at flue gas temperatures in the range of 1,400°F to 2,000°F. Above 2,000°F to 2,200°F, NH<sub>3</sub> is oxidized to NO, and below 1,400°F, the NO<sub>x</sub> reduction reaction stops. NO<sub>x</sub> reduction performance is maximized in the narrow temperature window of 1,600°F to 1,900°F.

The most critical operating and design factors associated with SNCR include the following:

- Temperature;
- Mixing;
- Reagent to NO<sub>x</sub> Ratio;
- Ammonium Sulfate Formation; and
- Hazardous material concerns.

Each of these factors is discussed in more detail below.

#### 1.1.3.1 Temperature Effects

The performance of SNCR is sensitive to flue gas temperature because optimal NO<sub>x</sub> reduction occurs in a limited temperature window. In addition, adequate residence time at this temperature is necessary to complete the reactions. Flue gas temperatures fluctuate in the bed, solids disengagement zone, and backpass sections of the circulating CFB boilers when there are changes in boiler load, fuel consumption, and combustion air temperature or flow. Because of this variability, the flue gas at the reagent injection point will not always be at the optimum temperature for NO<sub>x</sub> reduction.

Below the SNCR operating temperature range, the NH<sub>3</sub>/NO<sub>x</sub> reaction will not occur, and the unreacted NH<sub>3</sub> will either be emitted as NH<sub>3</sub> slip, or it will react with SO<sub>3</sub> to form ammonium salts, or will be incorporated in the ash. Above the optimum temperature, the amount of NH<sub>3</sub> that oxidizes to NO<sub>x</sub> increases and the NO<sub>x</sub> reduction performance deteriorates rapidly. Both laboratory work and field data show NH<sub>3</sub> slip to be a strong function of temperature. At temperatures at or above 1,900°F, unreacted NH<sub>3</sub> emissions decrease due to the NH<sub>3</sub> oxidation to NO<sub>x</sub>. At temperatures at or below 1,800°F, unreacted NH<sub>3</sub> emissions increase. Laboratory data show that maximum NO<sub>x</sub> removal and lowest NH<sub>3</sub> slip can be achieved by injecting urea at 1,900°F.

CFB boilers typically operate with bed temperatures in the range of 1,500° to 1,650°F to maximize in-bed SO<sub>2</sub> control. This lower operating temperature also reduces uncontrolled NO<sub>x</sub> emissions. However, for boilers requiring high (90 percent or higher) SO<sub>2</sub> removal using limestone injection, bed and solids disengagement section temperatures are below optimal for high NO<sub>x</sub> reductions and low NH<sub>3</sub> slip using SNCR. As a result, these boilers will not be able to achieve the higher end of potential NO<sub>x</sub> reductions (levels of up to 70 percent reduction) using SNCR technology. In addition, startup periods (when SNCR cannot be used) and lower operating loads exacerbate this condition.

#### 1.1.3.2 Mixing Effects

Complete mixing of the reagent with the flue gas can be difficult because of the relatively small volume of the boiler that is at the correct temperature for SNCR reagent injection. Failure to mix the SNCR reagents adequately with the flue gas may result in increased NH<sub>3</sub> slip and decreased NO<sub>x</sub> reduction. In a CFB boiler with high SO<sub>2</sub> control requirements, the reagent cannot be injected upstream of the optimum temperature window, because the char and CaO in the bed will catalyze the oxidation of NH<sub>3</sub> to NO<sub>x</sub>. Fortunately, the circulating CFB boiler proposed for

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<sup>1</sup> The urea injection process is commercially known as NO<sub>x</sub>OUT.

this project has a high temperature solids disengagement section operating in the temperature range of 1,500°F to 1,700°F. The disengagement section allows rapid mixing of the flue gases from the freeboard area of the boiler. Generally, injection of reagent just upstream of the disengagement section results in good mixing.

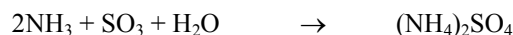
#### **1.1.3.3 Reagent to NO<sub>x</sub> Ratio**

In SNCR processes, the total amount of reagent (NH<sub>3</sub> or urea) injected into the flue gas is typically expressed as the molar ratio of NH<sub>3</sub> to inlet NO<sub>x</sub>. A molar ratio higher than 1.0 indicates that excess reagent has been injected. By injecting excess reagent, the chemical reactions described above are “forced” to the right favoring the reduction of NO<sub>x</sub> to N<sub>2</sub> and water. The SNCR process may require two to six times the amount of reagent theoretically required to achieve high NO<sub>x</sub> reduction. This is because even at optimum operating temperatures, some of the NH<sub>3</sub> injected oxidizes to NO<sub>x</sub>, and some of the injected ammonia will remain unreacted. Therefore, as the amount of excess reagent increases, the amount of NH<sub>3</sub> oxidizing to NO<sub>x</sub> increases or the amount of unreacted NH<sub>3</sub> emissions (or ammonia slip) increases.

The NO<sub>x</sub> reduction achievable and the amount of NH<sub>3</sub> slip also depend upon the inlet and outlet NO<sub>x</sub> concentrations. Lower inlet NO<sub>x</sub> concentrations require lower total NH<sub>3</sub> injection but a higher NH<sub>3</sub>-to-NO<sub>x</sub> ratio in order to obtain the same percentage reduction. Therefore, as NO<sub>x</sub> inlet concentrations decrease, relatively more reagent is required to achieve the same percent reduction. In the most recent BACT analysis found for a similar facility, the ammonia slip was limited by the PSD permit to no more than 10 ppmvd, corrected to 7.0% O<sub>2</sub>.

#### **1.1.3.4 Ammonium Sulfate Formation**

An important operating concern with SNCR is the reaction of SO<sub>3</sub> and unreacted NH<sub>3</sub> in the flue gases to form ammonium sulfate ((NH<sub>4</sub>)<sub>2</sub>SO<sub>4</sub>) and ammonium bisulfate (NH<sub>4</sub>HSO<sub>4</sub>). During combustion, a small percentage of SO<sub>2</sub> will be oxidized to SO<sub>3</sub>. The SO<sub>3</sub> reacts with free NH<sub>3</sub> and water to form ammonium sulfates:



Ammonium sulfates can condense on the cold end of the air heater and cause fouling. These deposits can cause a significant pressure drop across the air heater. Unfortunately, air soot blowing is often ineffective at removing the ammonium salt deposits. As a result, water washing is often necessary to remove the sticky, water-soluble material. Therefore, the boiler's air heater must be constructed of materials that can tolerate possible corrosion by the liquid waste and must be designed to accommodate water washing. Since the air heater must be cleaned with the boiler off-line, ammonium salt deposits can cause unplanned outages.

Ammonium sulfates can also cause fouling of baghouse fabric filters. These deposits can cause a significant pressure drop across the baghouse. As the pressure drop increases, the boiler capacity will reduce because the boiler fans will not be able to maintain design combustion air flows at the higher baghouse pressure drop. This problem occurred for a SNCR application on a stoker coal-fired boiler with a baghouse for particulate matter control. Although the boiler was specifically designed as a new unit application of SNCR, fabric filter differential pressures gradually increased from a normal/design range of 4 to 6 inches of water to over 12 inches of water. The increase in pressure drop restricted the boiler operation to the point that the SNCR operation was discontinued and an entirely new NO<sub>x</sub> control technology was installed.<sup>1</sup> Similar operating problems have been experienced at CFB boilers when high (greater than 10 to 20 ppm) ammonia slip levels have been measured.

Additionally, ammonium salts form as very small particles, and these fine particles increase exhaust plume opacity. For example, at a pulverized coal-fired boiler in California, the opacity of the exhaust plume visibly increased during the testing of NO<sub>x</sub>OUT technology (urea injection). The plume was attached to the exhaust stack outlet and persisted for more than an hour after urea injection was discontinued. It was assumed that the plume was caused by

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<sup>1</sup> Morrow, Robert, Jordan, Terry, and Hall, David; March 15-17, 1999. Methane de-NO<sub>x</sub> Reburn Process For Coal Fired Spreader Stoker Boilers. Council of Industrial Boiler Owners NO<sub>x</sub> Control XII Conference.



NH<sub>3</sub> slip combining with trace amounts of chloride from the coal and/or sulfate in the flue gas. The plume was minimized as NH<sub>3</sub> slip was reduced, but at the expense of NO<sub>x</sub> reduction.<sup>1</sup> Similar effects are known to occur at CFB boilers equipped with SNCR for NO<sub>x</sub> control. Based on operating experience, ammonia slip levels of less than 10 ppm are necessary:

- To minimize concern over ammonia salt formation, deposition, and emission which will minimize opacity and equipment fouling problems;
- To balance the emission of NH<sub>3</sub> relative to NO<sub>x</sub> from a health effects standpoint; and
- To optimize reagent consumption (costs) relative to NO<sub>x</sub> removal.

#### **1.1.3.5 Current Applications/Achievable NO<sub>x</sub> Reductions**

Application of SNCR is combustor/fuel-specific because the performance of SNCR is extremely temperature and mixing dependent. NO<sub>x</sub> and NH<sub>3</sub> emission levels achievable on one boiler will not necessarily translate into the same NO<sub>x</sub> and NH<sub>3</sub> emission levels achievable on a different type of CFB boiler using different fuel.

The temperature window in the solids disengagement section of the proposed circulating CFB boilers at the ADM Columbus facility is unknown at this time. Although excellent mixing of reagent is expected by injecting reagent just upstream of the solids disengagement section, the temperature in this section of the boiler could be below optimum SNCR reaction temperature. At lower load operation and during start up, the temperature will be too low for application of SNCR. Injection of reagent in the fluid bed would result in increased NO<sub>x</sub> emissions due to oxidation of the ammonia by the limestone/char bed. Injection downstream of the solids disengagement section would result in high, unreacted NH<sub>3</sub> emissions with little or no NO<sub>x</sub> reduction. The reaction of NH<sub>3</sub> slip with SO<sub>3</sub> would create ammonium salt deposition in the air heater and fabric filter, which could reduce operational reliability and increase the cost of ash disposal.

Individual boilers will exhibit unique performance characteristics. These performance characteristics will directly affect the ability of an SNCR system to meet a required NO<sub>x</sub> limit cost effectively, and without unduly restricting boiler operation due to increased maintenance outages. The performance of the proposed boilers at the ADM Columbus facility can only be established through actual operation. However, based on its extensive experience in constructing and operating solid-fuel CFB boilers, ADM has determined that the proposed boilers should be capable of achieving a long-term NO<sub>x</sub> emissions limit of 0.07 lb/MMBtu (excluding periods of cold-startup) without significant negative environmental (increased opacity and sulfate particulate emissions) or economic (ammonia consumption and vaporization) impacts. NO<sub>x</sub> emission limits less than 0.07 lb/MMBtu are not considered feasible for the proposed CFB boilers.

#### **1.1.4 Combustion Controls**

As is the case with other types of coal-fired boilers, combustion control (combustion air staging) is the most cost-effective means for reducing NO<sub>x</sub> emissions from CFB boilers. Combustion air staging is accomplished by introducing combustion air at two or more levels in the combustion section. Primary air is distributed through an air distributor plate to fluidize the bed. The amount of primary air is maintained below the stoichiometric requirement. Thus, the coal is initially combusted under fuel-rich conditions, which inhibit the formation of NO<sub>x</sub> in two ways. First, the amount of oxygen available to oxidize fuel and air nitrogen is minimized, minimizing the potential for the oxidation reaction. Second, the concentration of hydrocarbon-free radicals is increased. These radicals react with some of the NO<sub>x</sub>, reducing it to nitrogen.

Secondary air is introduced several levels above the bed in the freeboard area. The secondary air brings the total amount of combustion air up to the level needed to achieve good combustion efficiency and minimize emissions of CO and hydrocarbons. The amount of secondary combustion air and the time between primary and secondary air injection is important for minimizing NO<sub>x</sub> formation.

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<sup>1</sup> Comparato, J.R., R.A. Buchs, D.S. Arnold, and L.K. Bailey, 1991. NO<sub>x</sub> Reduction at the Argus Plant Using the NO<sub>x</sub> OUT Process, presented at the 1991 Joint Symposium on Stationary Combustion NO<sub>x</sub> Control, March 25-28, Washington, D.C.

#### 1.1.4.1 Important Operating Parameters

There are practical limits on how much secondary air can be introduced and how high in the freeboard area the secondary air can be introduced without reducing combustion efficiency, causing corrosion, and lowering steam temperature. The effectiveness of NO<sub>x</sub> reduction from combustion air staging is decreased by incomplete combustion, which results in high levels of unburned carbon, CO, and hydrocarbons. Incomplete combustion also decreases the combustion efficiency, increases the amount of coal consumed, and increases the solid waste volume due to the increased carbon content of the ash. In addition, substoichiometric oxygen levels create a reducing atmosphere on metal surfaces in the boiler, increasing the rate of metal corrosion. Air staging must occur in the refractory zone of the boiler to prevent tube erosion at the injection point.

Combustion air staging affects steam temperatures because less heat of combustion is released in the bed and more heat of combustion is released in the freeboard area. Thus, the amount of heat recovered from the fluid bed, the freeboard area, and the convective heat transfer section of the boiler changes when combustion control technology is being used, which can reduce the steam generation rate and temperature. Increased excess combustion air increases NO<sub>x</sub> formation because more oxygen is available to react with nitrogen. Thus, low excess combustion air levels are desirable for minimizing NO<sub>x</sub> formation.

#### 1.1.4.2 Current Applications/Achievable NO<sub>x</sub> Reductions

Combustion air staging has been used extensively for the control of NO<sub>x</sub> emission from circulating CFB boilers. Because of its extensive use to control NO<sub>x</sub> emissions from circulating CFB boilers, combustion control is considered the baseline for the proposed boilers. The estimated baseline emissions are 0.20 lb NO<sub>x</sub>/MMBtu (equal to the NSPS limit for these units).

#### 1.1.5 NO<sub>x</sub> Control Hierarchy

Based on the previous technology discussions, Table 1-2 presents the NO<sub>x</sub> BACT hierarchy. It has been assumed that to meet the NSPS limit, SNCR technology is not required in the baseline control option.

**Table 1-3. NO<sub>x</sub> Control Hierarchy**

Control Option	Percent Control verses Combustion Control	NO <sub>x</sub> Emission Rate lb/MMBtu
CC+SNCR (SNCR @ 0.05)	75	0.05
CC+SNCR (SNCR @ 0.08)	65	0.07
CC+SNCR (SNCR @ 0.15)	25	0.15
Combustion Control only	0	0.20

#### 1.1.6 Impacts Analyses for NO<sub>x</sub> Controls

Table 1-3 presents the impacts of three levels of NO<sub>x</sub> control using SNCR technology. Although control levels less than 0.07 lb/MMBtu are considered as technically infeasible due to the unacceptable environmental impacts of ammonia slip levels greater than 10 ppm, the impacts of controlling NO<sub>x</sub> to 0.05 lb/MMBtu are presented here for comparison.

**Table 1-4. Economic, Energy, and Environmental Impacts of SNCR Technology**

<b>SNCR CONTROL LEVEL, lb/MMBtu →</b>	<b>0.05*</b>	<b>0.07</b>	<b>0.15</b>
<b>ECONOMIC IMPACTS</b>			
<b>Total Capital Requirement:</b>	\$1,227,951	\$1,203,169	\$1,190,778
<b>Annual Fixed O&amp;M Costs:</b>	\$82,426	\$82,42	\$82,426
<b>Annual in Variable O&amp;M Costs:</b>	\$1,101,156	\$566,054	\$283,939
<b>Capital Recovery Costs:</b>	\$143,670	\$140,771	\$139,321
<b>Total Annual Costs:</b>	\$1,327,252	\$789,251	\$505,687
<b>NO<sub>x</sub> Reduction Cost Effectiveness:</b>	\$2,694	\$1,848	\$3,077
<b>Incremental NO<sub>x</sub> Reduction Cost Effectiveness:</b>	\$5,555	\$2,174	
<b>ENERGY IMPACTS</b>			
<b>NH<sub>3</sub>/NO<sub>x</sub> ratio:</b>	4	2	1
<b>MMBtu/hr Boiler Efficiency Penalty:</b>	37	19	10
<b>ENVIRONMENTAL IMPACTS</b>			
<b>Tons per Year NO<sub>x</sub> Emissions:</b>	159	122	476
<b>Tons per Year NO<sub>x</sub> Reduction:</b>	493	427	164
<b>NH<sub>3</sub> PPM:</b>	20	<10	<5
<b>Tons per Year of NH<sub>3</sub> Slip:</b>	43	22	11
<b>Tons per Year of Increased Particulate:</b>	168	42	21
<b>Annual Emissions Reduction (NO<sub>x</sub>-NH<sub>3</sub>-PM<sub>10</sub>):</b>	282	363	132
<p>*Not considered to be technically feasible due to increased opacity and fabric filter plugging from high levels of ammonium salt formation. Cost impacts do not include increase in system pressure drop due to fabric filter plugging and more frequent bag filter replacement.</p> <p><b>Note: All calculations are on a per boiler basis.</b></p>			

#### **1.1.6.1 Economic Impacts of SNCR**

To assess the economic costs of SNCR, the U.S. EPA Coal Utility Environmental Cost (CUECost) model was used. Energy costs include power cost for the increased baghouse pressure drop, steam to assist with the injection of ammonia, and electrical costs for operation of the ammonia injection system. The capital cost of the three SNCR systems varies only slightly as a function of the ammonia injection rates required for the three levels of control. The assumed molar ratios for the three levels of control are; 1.0 for the 0.15 lb/MMBtu case, 2.0 for the 0.07lb/MMBtu case, and 4.0 for the 0.05 lb/MMBtu case. The primary difference in annual cost between the three cases is due to the injection steam requirement, which is assumed to vary proportionately with ammonia flow.

#### **1.1.6.2 Energy and Environmental Impacts of SNCR**

The energy impact component for each case comprises injection steam usage, fan power requirements (for increased pressure drop due to ammonium sulfate buildup on the baghouse fabric filter), and the electrical energy requirement for the ammonia system. The injection steam requirement accounts for approximately 80 percent of the energy requirement.

The environmental impact for each case identifies the NO<sub>x</sub> emissions decreases along with the corresponding increases in ammonia slip, particulate emissions and opacity. The increase in ammonia slip results from the higher ammonia to NO<sub>x</sub> ratio required to achieve the higher reduction levels. The increased particulate emissions result

from the reaction of slip ammonia with SO<sub>3</sub> to form ammonium salts. The increased presence of the ammonium salts is the cause of the increase in stack opacity. In an effort to quantify the overall impact of NO<sub>x</sub> emission reductions with increase in ammonia slip and fine particulates, the change in total annual emissions of these three pollutants (NO<sub>x</sub>, NH<sub>3</sub>, PM<sub>10</sub>) is calculated by subtracting the estimated emissions of ammonia and ammonium sulfate (fine particulate matter) from the decrease in NO<sub>x</sub> emissions. This calculation shows that the overall emissions impact of reducing NO<sub>x</sub> emissions from 0.07lb/MMBtu to 0.05 lb/MMBtu is negative. In other words, the decrease in tons of NO<sub>x</sub> emissions is more than offset by an increase in the tons of NH<sub>3</sub> and particulate matter emissions.

### 1.1.7 Proposed BACT Limit for NO<sub>x</sub> Emissions

Based on the above analysis, ADM proposes SNCR control with an emission limit of 0.07lb/MMBtu as BACT (on a 3-day rolling average basis and excluding periods of cold-startup). The BACT selection rationale follows:

SCR is considered technically infeasible for the proposed CFB at the Columbus facility because the catalyst will be rapidly deactivated due to:

- The poisoning effect of calcium oxide, a strong alkali, on the catalyst acidic reactive sites; and
- The fouling effect of the high particulate loading in the flue gas path where the SCR must be located to be in the proper operating temperature range.

SNCR control levels less than 0.07 lb/MMBtu are rejected as BACT based on the following environmental impacts:

- Stack opacity increases by 10 percentage points (<10% to 20% opacity) or more;
- Ammonia slip level increases above 10 ppm increase condensable PM emissions downstream;
- The incremental cost effectiveness of \$5,600 per ton of additional NO<sub>x</sub> emissions reduction is excessive, especially when considering the fact that these costs do not include the effects of increased system pressure drop due to fabric filter plugging and the costs of more frequent replacement of plugged filter bags; and
- The increases in fine particulate matter and ammonia emissions make the proposed BACT limit for particulate matter unattainable.

The proposed NO<sub>x</sub> BACT limit below is based on an emission rate of 0.07 lb/MMBtu:

Pollutant	Emission Limit	Compliance Demonstration
NO <sub>x</sub>	52.5 lb/hr	per boiler; 30-day rolling average using continuous monitor; excluding periods of "cold startup" <sup>1</sup>
NH <sub>3</sub>	10 ppm	appropriate stack test methods

## 1.2 Sulfur Dioxide, Sulfuric Acid Mist (H<sub>2</sub>SO<sub>4</sub>), and Fluoride (F) Control Technology Review

Emissions of SO<sub>2</sub> result from the oxidation of fuel sulfur. During combustion, the majority of the fuel sulfur is emitted as SO<sub>2</sub>. A portion of the fuel sulfur is further oxidized to SO<sub>3</sub>. At temperatures below about 600°F, sulfur trioxide readily combines with moisture in the flue gas or in the atmosphere to form H<sub>2</sub>SO<sub>4</sub>. Emissions of F result from the volatilization of fluorides contained in solid fuels and limestone. During combustion, the majority of the

<sup>1</sup> A cold startup period is defined as that period of time when a CFB boiler is proceeding to increase the temperature in the lower combustor from less than 400°F to at least 1500°F. This period shall last no more than 48 hours and NO<sub>x</sub> emissions data from this period shall be excluded when determining compliance with the proposed BACT limits. Ammonia injection shall begin as soon as the lower combustor temperature reaches 1500°F and the cold startup period will end at this time. All data from cold startup periods after the first 48 hours, or while ammonia is injected in the boiler, will be included in determining compliance with the BACT limit.

volatilized fluorides are emitted as HF vapors or mist. These sulfur and fluoride compounds are acidic and can be controlled using the same control technologies.

### 1.2.1 Identification of Technically Feasible Controls

First, the RBLC database was reviewed to identify the technologies used to control SO<sub>2</sub>, H<sub>2</sub>SO<sub>4</sub>, and F emissions from fluidized bed boilers. Data from the RBLC for CFB coal-fired boilers are summarized in Table 1-4. This data indicates that for:

- SO<sub>2</sub> Control - novel integrated flue gas desulfurization (NIDS), in-bed limestone injection, and fuel sulfur specification are used;
- H<sub>2</sub>SO<sub>4</sub> Control - in-bed limestone injection is used; and
- F Control - baghouse is used.

Review of the RBLC for controls applied to other types of coal-fired boilers permitted under the PSD program since 1992 identified the use of wet and dry flue gas desulfurization (FGD) technologies, and particulate controls (ESP and FF baghouse) for the control of SO<sub>2</sub>, H<sub>2</sub>SO<sub>4</sub>, and F.

The proposed CFB boilers are subject to the standards of performance for new stationary sources under 40 CFR Part 60, Subpart Db, "Industrial-Commercial-Institutional Steam Generating Units". The Subpart Db SO<sub>2</sub> emission limitations for the proposed units require 90 percent control. Because the BACT requirements must, at a minimum, meet this performance standard, this limitation establishes the "baseline" or maximum allowable emission rate for the evaluation of SO<sub>2</sub> controls in this Control Technology Review.

**Table 1-4.**  
**Controls Identified in Recent BACT Determinations for CFB Boilers**

COMPANY/FACILITY	RBLC ID	PERMIT DATE	SO <sub>2</sub> Control / Removal %	H <sub>2</sub> SO <sub>4</sub> Control	HF Control
Enviropower	Benton, IL <sup>a</sup>	07/03/01	CFB with sorbent injection baghouse / 92%	No limit	CFB with sorbent injection baghouse
Kentucky Mountain Power, LLC	Ary, KY <sup>a</sup>	05/04/01	NIDS- Novel Integrated Desulfurization System	CFB design	Baghouse
JEA NORTHSIDE GENERATING STATION	FL-0178	7/14/1999	LIMESTONE INJECTION / 90 % per NSPS	No limit	No limit
ARCHER DANIELS MIDLAND COMPANY Decatur Units 9 & 10	IL-0060	12/24/1998	LIMESTONE INJECTION / 92%	No limit	Baghouse
ARCHER DANIELS MIDLAND COMPANY Cedar Rapids Unit 5	IA-0051	6/30/1998	LIMESTONE INJECTION / 92%	No limit	No limit
ARCHER DANIELS MIDLAND COMPANY Cedar Rapids Unit 6	IA-0046	6/30/1998	LIMESTONE INJECTION / 92%	No limit	No limit
TOLEDO EDISON CO. - BAYSHORE PLANT	OH-0231	6/20/1997	LIMESTONE INJECTION / 90%	No limit	No limit
YORK COUNTY ENERGY PARTNERS	PA-0132	7/25/1995	LIMESTONE INJECTION & <=2% SULFUR IN COAL / 92%	No limit	No limit
NORTHAMPTON GENERATING CO.	PA-0134	4/14/1995	LIMESTONE INJECTION / 92%	No limit	No limit
ARCHER DANIELS MIDLAND COMPANY Decatur Units 7 & 8	IL-0058	8/11/1994	LIMESTONE INJECTION / 90% per NSPS	No limit	No limit

AES WARRIOR RUN, INC.	MD-0022	6/3/1994	LIMESTONE INJECTION / 95%	LIMESTONE INJECTION	No limit
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**Table 1-4.**  
**Controls Identified in Recent BACT Determinations for CFB Boilers. (Continued)**

COMPANY/FACILITY	RBLC ID	PERMIT DATE	SO <sub>2</sub> Control / Removal %	H <sub>2</sub> SO <sub>4</sub> Control	HF Control
FORT DRUM HTW COGEN FACILITY	NY-0070	3/1/1994	LIMESTONE INJECTION / 90%	No limit	No limit
NORTH BRANCH ENERGY PARTNERS LP	PA-0058	1/25/1993	LIMESTONE INJECTION / 46%	No limit	None listed
a- Projects not listed in RBLC					

Based on the above review, the following SO<sub>2</sub>, H<sub>2</sub>SO<sub>4</sub>, and F controls that will be evaluated in this Control Technology Review are:

- Limestone Injection;
- Wet and Dry FGD; and
- Use of lower sulfur fuels.

Because limestone injection is an inherent part of the CFB process, this technology will be evaluated as the baseline control option. Wet and dry FGD will be evaluated as add-on controls after achieving the maximum level, economically, of limestone injection control. Use of lower sulfur fuels is not evaluated as a pre-process control option because the project will use at least a 75:25 blend of low-sulfur western and higher-sulfur Midwestern coals to ensure reliable boiler operation (i.e., the use of additional low-sulfur coal is not a technically feasible control option due to the performance characteristics of the CFB technology).<sup>1</sup> The following discussion describes these technologies and the potentially achievable emission rates.

### **1.2.2 Control Technology Description and Emission Hierarchy**

The following control technology discussion will be focused on the control of SO<sub>2</sub>. Each of the SO<sub>2</sub> control technologies discussed, except the use of low sulfur fuels, has a percent control for H<sub>2</sub>SO<sub>4</sub> and fluorides approximately equivalent to SO<sub>2</sub> control. As such, the impact of SO<sub>2</sub> controls on H<sub>2</sub>SO<sub>4</sub> and fluorides will be discussed further under the environmental impacts analyses for the SO<sub>2</sub> control options.

#### **1.2.2.1 Fluidized Bed Boilers Limestone Injection for SO<sub>2</sub> Control**

The development of fluidized bed boiler technology has been driven largely by the need to reduce SO<sub>2</sub> and NO<sub>x</sub> emissions from the combustion of coal and high sulfur fuels such as coal. The major advantages to the fluidized bed boiler technology are the ability of controlling emissions of SO<sub>2</sub> to very low levels “in-situ” without post combustion air pollution control systems, and the ability to process a wide range of solid fuels without modifications. The fluidized bed boiler combusts solid fuel(s) in a fluid bed mixture of fuel, char, ash, and other materials (limestone or sand) used to provide the desired bed characteristics. Combustion air forced in at the bottom of the furnace keeps the bed mixture in a constantly upward moving fluid flow. Combustion takes place within the furnace at low combustion temperatures ranging from 1,500 to 1,650°F. The low combustion temperature allows for good absorption of SO<sub>2</sub> with alkaline minerals (calcium, sodium, etc) contained in the fuel ash or added with the bed material (i.e., limestone). Additionally, the low combustion temperature reduces ash fusion problems associated with the combustion of many coals in conventional boilers.

<sup>1</sup> This approach to fuel blending is based on ADM’s experience with its Decatur CFB units. It may ultimately be possible to run higher low-sulfur blends, but ADM cannot determine if such operation is possible at this time.

There are two general types of fluidized bed boilers: atmospheric (AFB) and pressurized (PFB). AFB boilers have been used commercially for many years with the circulating bed type being the predominate process type. PFB boilers are a developing technology with few commercial installations and this technology was not considered for the Columbus plant. ADM has experience with atmospheric CFB technology and has successfully constructed and operated CFB boilers.

There are two major AFB boiler types: the “bubbling” bed, and the “circulating” bed boiler. In the bubbling bed boiler, the bed of materials including the limestone, fuel, and ash is suspended by the combustion air blowing upward through an air distributor plate at relatively low velocities of 1 - 5 ft/sec. The bed itself is typically about 4 feet deep in its fluidized condition, and is characterized by a sharp density profile at the top of the bed. The sharp drop off in density indicates the end of the *bubbling* fluidized bed. In a bubbling bed boiler, the bed level is easy to see, and there is a distinct transition between the bed and the space above. However, due to the low bed velocities, maintaining stable operation for large furnaces (those with heat inputs greater than 1,000 MMBtu/hr) is difficult and bubbling bed boilers are typically used for small boilers (<200 MMBtu/hr).

The fluidized bed boiler proposed for this project is a CFB boiler. CFB boilers have high fluidizing air velocities ranging from 10 to 20 ft/sec, lack a distinct transition from the dense bed at the bottom of the furnace to the dilute zone above, and have very high flow rate of re-circulated solids. The high fluidizing air velocity results in a *turbulent* fluidized bed and a high rate of entrained solids carried out of the boiler. These solids are separated from the combustion gases in a solids disengagement section and returned to the furnace to improve combustion efficiency and limestone utilization.

To control SO<sub>2</sub> emissions directly in the boiler, limestone is injected with fuel directly into the fluidized bed. Within the furnace, limestone is first “calcined” to calcium oxide. Calcium oxide then reacts with SO<sub>2</sub> in the fluidized bed to form calcium sulfate. The chemistry of the SO<sub>2</sub> reaction includes the following:

- 1. Calcination:**  $\text{CaCO}_3 (\text{s}) + 766 \text{ Btu/lb (of CaCO}_3) \rightarrow \text{CaO (s)} + \text{CO}_2 (\text{g})$
- 2. Adsorption:**  $\text{SO}_2 (\text{g}) + \frac{1}{2}\text{O}_2 (\text{g}) + \text{CaO (s)} \rightarrow \text{CaSO}_4 (\text{s}) + 6733 \text{ Btu/lb (of S)}$
- 3. Overall:**  $\text{CaCO}_3 (\text{s}) + \text{SO}_2 (\text{g}) + \frac{1}{2}\text{O}_2 (\text{g}) \rightarrow \text{CaSO}_4 (\text{s}) + \text{CO}_2 (\text{g}) + 5967 \text{ Btu/lb (of S)}$

Calcium sulfate or *gypsum* is chemically stable in the fluidized bed at normal operating temperatures and is rejected from the system in the furnace bottom ash draw and in the fabric filter baghouse ash draw. The ash draw contains primarily fuel ash, gypsum, unreacted calcium oxide, and char and is disposed off as a non-hazardous solid waste.

#### 1.2.2.2 Important Operating Factors

The primary factor affecting CFB boiler performance is the calcium-to-sulfur molar feed (Ca/S) ratio, which is a function of the fuel sulfur content and the percent SO<sub>2</sub> removal desired. As the calcium content of the bed increases, greater amounts of SO<sub>2</sub> are removed. The importance of the Ca/S ratio extends beyond SO<sub>2</sub> removal; it also affects the mass rate of bed material flowing through the furnace/boiler, which affects the size of the furnace/boiler, and the operating costs for limestone, furnace wall erosion, and auxiliary power requirements. As the Ca/S ratio increases, the mass of solids flowing through the unit increases.

High sulfur coals and high SO<sub>2</sub> control efficiencies require very high limestone injection rates. This results in lower cyclone temperatures because the amount of heat of combustion absorbed in the radiant heat section of the boiler increases with higher solids (limestone) circulating rates. For each solid fuel and desired SO<sub>2</sub> capture rate, there is an optimum Ca/S ratio and bed temperature. However, at very high Ca/S ratios, the addition of more Ca does not result in a proportional increase in SO<sub>2</sub> removal. As such, there is a practical limit to the amount of limestone that can be economically injected/circulated. Thus, the maximum in-bed SO<sub>2</sub> reduction that can economically be achieved when firing high sulfur solid fuels is approximately 95 percent, above which the exponentially increasing limestone injection/circulation requirement would result in unacceptable furnace wall and boiler tube erosion rates and combustion efficiency losses associated with limestone calcination.



However, the converse is also true; it is easier to obtain high removal efficiencies with high sulfur coals relative to very low sulfur coals. This is because there is a concentration of SO<sub>2</sub> where the driving force for the reaction of SO<sub>2</sub> with CaO is so small that it becomes the controlling factor in the furnace design. For example, the lowest SO<sub>2</sub> emission limit for CFB boilers found in the RBLC is 0.129 lb/MMBtu using limestone injection. Lowering the SO<sub>2</sub> emissions below this level using limestone injection technology is technically infeasible due to equilibrium limitations of the in-situ technology.

#### **1.2.2.3 Achievable SO<sub>2</sub> Reduction**

Depending upon the Ca/S mole ratio within the bed, SO<sub>2</sub> removal rates in excess of 90 percent have been achieved in similar CFB boilers. Recent BACT determinations in Table 1-4 have been based on CFB boiler SO<sub>2</sub> reductions of 90 – 92 percent for moderate to low sulfur coals.

### **1.2.3 Flue Gas Desulfurization**

Until recently, the use of a fluidized bed boiler with limestone injection for SO<sub>2</sub> control was, by itself, considered BACT. In 1998, the U.S. EPA Region 2 issued a PSD permit for two CFB boilers to be installed in Puerto Rico, which required post combustion FGD systems to achieve further emission reductions over the use of limestone injection in the FB boilers. This decision was appealed to the U.S. EPA Environmental Appeals Board (EAB) to review the regulatory basis for this decision. In its May 27, 1999 decision, the EAB determined that although this combination of controls has never been demonstrated in practice, the fact that each individual control has been demonstrated in practice adequately justifies the use of this combination of controls. Subsequently, at least one CFB boiler project was permitted with post furnace SO<sub>2</sub> control using a duct sorbent inject technology called NIDS (Novel Integrated Desulfurization System).

The FGD technologies common to large conventional pulverized coal-fired industrial boilers include two major types: “wet” systems and “dry” systems. Wet FGD systems contact the combustion flue gases with an alkaline liquid or slurry, resulting in a low-temperature (approximately 120°F), moisture saturated, flue gas. Wet FGD systems operating in the U.S. on coal-fired boilers include wet sodium carbonate and hydroxide systems, wet lime and limestone systems with and without forced oxidation, and Wellman-Lord regenerable systems.

Dry FGD systems contact the combustion flue gases with alkaline solids or slurries resulting in a flue gas containing dry reacted/unreacted sorbent at temperatures 20°F or more above the saturation point. The dry reacted/unreacted sorbent solids are collected using a baghouse. Dry FGD systems operating commercially in the U.S. primarily include lime spray drying systems, and sodium bicarbonate in-duct injection systems. The cost effectiveness of any of the FGD systems will be very high (>\$10,000/ton) because of the low SO<sub>2</sub> concentrations remaining in the combustion flue gases after 90-92 percent control using in-bed limestone injection. Although technically feasible, not all of the above mentioned FGD systems will be evaluated further. Table 1-5 presents the reasons why some FGD technologies were not considered further in this analysis.

#### **1.2.3.1 Wet Flue Gas Desulfurization Systems Achievable SO<sub>2</sub> Reductions**

The use of a wet flue gas desulfurization system such as a wet limestone forced oxidation system has the potential to reduce SO<sub>2</sub> emissions by over 90 percent. Using a 90 percent control level, results in an emission rate of 0.025 lb SO<sub>2</sub>/MMBtu representing an overall SO<sub>2</sub> control efficiency of 99 percent. The lowest permitted SO<sub>2</sub> emission rate since 1992 for any coal-fired boiler in the RBLC using wet scrubbing technology is 0.08 lb/MMBtu.<sup>1</sup>

### **1.2.4 Dry Flue Gas Desulfurization Systems**

The use of a dry flue gas desulfurization system such as lime spray drying followed by a baghouse has the potential to reduce SO<sub>2</sub> emissions by 75 to 90 percent. Using a 75 percent control level, results in an emission rate of 0.063 lb SO<sub>2</sub>/MMBtu, which is an overall SO<sub>2</sub> control efficiency of 97.5 percent. The lowest permitted SO<sub>2</sub>

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<sup>1</sup> RBLC ID UT-0053 is a 500 MW (~5000 MMBtu/hr) coal-fired boiler permitted on 3/16/1998 with a 90 percent control wet scrubber.

emission rate since 1992 for any coal-fired boiler in the RBLC using lime spray dryer scrubbing technology is 0.086 lb/MMBtu.<sup>1</sup>

The use of a dry flue gas desulfurization system such as duct injection using lime has the potential to reduce SO<sub>2</sub> emissions up to 50 percent. Using a 50 percent control level results in an emission rate of 0.125 lb SO<sub>2</sub>/MMBtu, which is an overall SO<sub>2</sub> control efficiency of 95 percent. Two CFB boiler projects have been recently permitted with duct injection technology with emission rates of 0.13 and 0.25 lb SO<sub>2</sub>/MMBtu.<sup>2</sup>

**Table 1-5.**  
**FGD Systems Operating on Conventional Coal-Fired Boilers Not Evaluated**

<b>FGD Process</b>	<b>Reasons for Not Evaluating Further</b>
Wellman-Lord	<ul style="list-style-type: none"> <li>• Complex chemical processes; power boiler plants generally do not have staff with knowledge of these processes.</li> <li>• Economics tied to market for H<sub>2</sub>SO<sub>4</sub>. Annualized cost of control much higher than other FGD processes.</li> <li>• No new units installed in U.S. in over 20 years and these units are no longer operational.</li> </ul>
Dual Alkali	<ul style="list-style-type: none"> <li>• More complex process than wet L/LS FGD with high annualized costs.</li> <li>• Wet ash and FGD byproduct is difficult to manage presenting serious solid waste disposal issues with little potential for reuse.</li> <li>• Sodium salts in dual alkali sludge waste complicate reuse and/or disposal.</li> <li>• No new units installed in U.S. in over 15 years.</li> </ul>
Wet Sodium	<ul style="list-style-type: none"> <li>• High reagent cost limits technology to smaller applications (&lt;250 MMBtu/hr).</li> <li>• Large quantities of highly alkaline liquid waste, which must be treated and/or disposed of.</li> <li>• Wet ash and FGD byproduct is difficult to manage presenting serious solid waste disposal issues with little potential for reuse. Sodium exacerbates ground water impact issues.</li> </ul>
Sodium Bicarbonate In-duct Injection	<ul style="list-style-type: none"> <li>• High reagent cost limits technology to smaller applications and/or lower SO<sub>2</sub> reduction levels.</li> <li>• Large quantities of sodium waste presents serious solid waste disposal issues because sodium exacerbates ground water impact issues.</li> </ul>

### **1.2.5 Low Sulfur Fuels**

Because sulfur dioxide emissions occur from the oxidation of sulfur in the fuels, they may also be controlled by limiting fuel sulfur content. High sulfur fuel is available at low cost in some locations in the country because the high sulfur values limit their use in conventional power plants that do not have 90+ percent SO<sub>2</sub> control systems. Limiting fuel sulfur content to preclude the use of economically available high sulfur fuels in a state-of-the-art facility would redefine the project and would also be contrary to recently issued permits in Illinois, Iowa, and Ohio. In evaluating the potential alternatives for a proposed project, the U.S. EPA's Draft New Source Review Manual, EPA states:

<sup>1</sup> RBLC ID AK-0024 is a 50 MW (~500 MMBtu/hr) entrained combustor boiler using spray dryer FGD permitted on 11/14/2002.

<sup>2</sup> Environpower of Benton, IL and Kentucky Mountain Power, LLC of Ary, KY. See Table 1-8.

*"Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives. For example, applicants proposing to construct a coal-fired electric generator, have not been required by EPA as part of a BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity). However, this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire. Thus, a gas turbine normally would not be included in the list of control alternatives for a coal-fired boiler." [p. B-13]*

In a PSD appeal decision from the U.S. EPA's EAB in the matter of Hawaiian Commercial and Sugar Company, PSD Appeal No. 92-1, page 99, the EAB reaffirmed that the Agency is not required to redefine the source to reduce emissions.

Fuel sulfur content limits have been established as a part of the BACT limits for the AES Puerto Rico facility, and the YORK COUNTY ENERGY PARTNERS facility in Pennsylvania. These permits limit coal sulfur contents to 1.0 percent and 2.0 percent, respectively. It is important to note, however, that the permits issued to CFB boilers in Ohio, Illinois, and Iowa *after* the issuance of the AES Puerto Rico and the YORK COUNTY ENERGY PARTNERS permits did *not* include fuel sulfur content limits as part of the BACT conditions.

In the control technology analysis for the Inter-Power of New York facility, U.S. EPA Region II concluded that limiting coal sulfur contents to levels below 1.87 percent was economically infeasible because it resulted in incremental control costs of \$4,000 - \$6,000 per ton even though a facility in Massachusetts was recently required to limit emissions to a lower level. These incremental control costs were based on a 94 percent reduction in SO<sub>2</sub> emissions from the proposed pollution control systems. This PSD permit was upheld by the U.S. EPA Environmental Appeals Board (EAB) in Decision 5 EAD 130 on March 16, 1994.

In Nebraska, the economically available coals are low sulfur coals from Wyoming.<sup>1</sup> As such, the primary fuel for the proposed Columbus facility is low sulfur western subbituminous or bituminous coals. This fuel is a moderate Btu, low sulfur, low moisture, and low ash fusion fuel. The design sulfur, heat content, and uncontrolled SO<sub>2</sub> emission rate are:

- 0.62 weight percent sulfur;
- 8,781 Btu/pound (higher heating value); and
- 1.4 lb SO<sub>2</sub>/MMBtu.

Based on ADM's experience, up to 25% (on a mass or tonnage basis) of Midwestern bituminous coal may be needed to ensure reliable boiler operation. Thus, for purposes of this BACT analysis, ADM has assumed that such a blend is the baseline for these boilers. The design sulfur, heat content, and uncontrolled SO<sub>2</sub> emission rate for the Midwestern bituminous coal are:

- 2.75 weight percent sulfur;
- 10,600 Btu/pound (higher heating value); and
- 5.17 lb SO<sub>2</sub>/MMBtu.

Assuming a blend of 75 wt. percent Wyoming coal and 25 wt. percent Midwestern bituminous coal, the design uncontrolled SO<sub>2</sub> emission rate would be 2.5 lb SO<sub>2</sub>/MMBtu.

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<sup>1</sup> See Table 22. Destination and Origin of Coal by State, 2000, U.S. Department of Energy, Energy Information Agency (<http://www.eia.doe.gov/cneaf/electricity/cq/t22p3.html>).

Additionally, up to 20 percent tire-derived fuel (TDF) and biomass may also be fired with the coal. Of these, tire-derived fuel would have the greatest impact on emissions because this fuel typically contains 1.5 percent by weight sulfur. The design sulfur, heat content, and uncontrolled SO<sub>2</sub> emission rate are:

- 1.49 weight percent sulfur;
- 15,817 Btu/pound (higher heating value); and
- 1.9 lb SO<sub>2</sub>/MMBtu.

Assuming a blend of 80 wt. percent Wyoming coal and 20 wt. percent TDF the design uncontrolled SO<sub>2</sub> emission rate would be 1.55 lb SO<sub>2</sub>/MMBtu.

### 1.2.6 SO<sub>2</sub> Control Hierarchy

Based on the previous technology discussions, Table 1-6 presents the proposed SO<sub>2</sub> BACT hierarchy. Note that the uncontrolled emission rate is only theoretical because a fluidized bed boiler cannot operate without limestone for control of SO<sub>2</sub> due to the corrosive atmosphere in the furnace of coal-fired fluidized bed boilers. Typically, greater than 80 percent SO<sub>2</sub> control is required to minimize the corrosive effects of fuel sulfur on the furnace/cyclone walls. The following sections will present the economic, energy, and environmental impacts for the control hierarchy.

**Table 1-6. SO<sub>2</sub> Control Hierarchy**

Control Option	Percent Control* verses Uncontrolled	SO <sub>2</sub> Emission Rate lb/MMBtu
Limestone Injection + Wet FGD (LI+WFGD)	99.0	0.025
Limestone Injection + Spray Dry FGD (LI+SDFGD)	97.5	0.063
Limestone Injection + Duct Injection FGD (LI+DIFGD)	95.0	0.125
Additional Limestone Injection (ALI)	92.0	0.20
NSPS Baseline using Limestone Injection (LI)	90.0	0.25
* Based on average uncontrolled value of 2.5 lb SO <sub>2</sub> /MMBtu.		

### 1.2.7 Impacts Analyses for SO<sub>2</sub>/H<sub>2</sub>SO<sub>4</sub>/HF Controls

Table 1-7 presents the impacts of three levels SO<sub>2</sub> control over LI technology at 90.0 percent control using FGD technology and additional limestone injection (ALI).

**Table 1-7.**  
**Economic, Energy, and Environmental Impacts of FGD Technology plus LI**

<b>CONTROL @ lb SO<sub>2</sub>/MMBtu →</b>	<b>WFGD @ 0.025</b>	<b>SDFGD @ 0.063</b>	<b>DIFGD @ 0.125</b>	<b>ALI @ 0.20</b>
<b>ECONOMIC IMPACTS</b>				
<b>Total Capital Requirement:</b>	\$45,855,419	\$30,070,051	\$21,061,726	\$0*
<b>Annual Fixed O&amp;M Costs:</b>	\$3,061,294	\$2,121,594	\$1,629,351	\$346,900*
<b>Annual Variable O&amp;M Costs:</b>	\$405,830	\$193,234	\$247,951	\$755,225*
<b>Capital Recovery Annual Costs:</b>	\$5,794,821	\$3,518,196	\$2,464,222	0*
<b>Total Annual Costs:</b>	\$9,261,946	\$5,833,024	\$4,341,524	\$1,102,125*
<b>Cost Effectiveness over LI:</b>	\$12,691	\$9,591	\$10,708	\$6,710
<b>ENERGY IMPACTS</b>				
<b>MMBtu/hr of Electricity:</b>	19.4	5.3	5.3	0*
<b>ENVIRONMENTAL IMPACTS</b>				
<b>Annual SO<sub>2</sub> Reduction over LI, tons:</b>	730	608	405	164
<b>Annual Increase Solid Waste over LI, tons:</b>	2,514	1,971	2,606	16,848
*Incremental costs over LI @ 0.25 lb/MMBtu				
<b>Note: All calculations are on a per boiler basis.</b>				

#### **1.2.7.1 SO<sub>2</sub>/H<sub>2</sub>SO<sub>4</sub>/HF Economic Impacts Analysis**

To assess the economic costs of a WFGD system, the U.S. EPA CUECost model was used. The economics of the WFGD SO<sub>2</sub> control system are based on the CUECost Limestone Forced Oxidation system. A 90 percent reduction for WFGD (instead of 95%) was assumed due to the low inlet SO<sub>2</sub> concentration. Additionally because particulate emissions from a wet FGD system can not achieve a particulate matter emission limit of 0.015, the costs of a wet ESP to reduce WFGD particulate matter emissions to 0.015 lb/MMBtu are estimated using the CUECost dry ESP model. Although CUECost does not have a wet ESP control option, the cost of a conventional ESP was developed based on an inlet particulate matter loading of 0.03 lb/MMBtu.

To assess the economic costs of a SDFGD system, the U.S. EPA CUECost model was used. The economics of the SDFGD SO<sub>2</sub> control system are based on the CUECost Lime Spray Dryer system. A 75 percent reduction for SDFGD (instead of 90%) was assumed due to the low inlet SO<sub>2</sub> concentration. The fabric filter baghouse costs to reduce SDFGD particulate matter emissions to 0.015 lb/MMBtu are not included because a fabric filter baghouse system is considered as part of the base cost of the project for particulate matter control and for a new application, the spray dryer absorbers can be located before the baghouse. The baghouse solids handling equipment (e.g., hoppers) would need to be upsized somewhat to handle the increased solids loading, but this cost is judged to be minor.

To assess the economic costs of a DIFGD system, the U.S. EPA CUECost model was used. The economics of the DIFGD SO<sub>2</sub> control system are based on the CUECost Lime Spray Dryer system excluding the cost of the spray dryer absorber. A 50 percent reduction for DIFGD was assumed due to the low inlet SO<sub>2</sub> concentration. The fabric filter baghouse costs to reduce DIFGD particulate matter emissions to 0.015 lb/MMBtu are not included because a fabric filter baghouse system is considered as part of the base cost of the project for particulate matter control and for a new application, the duct injection can be located before the baghouse. Again, the baghouse solids handling equipment would need to be upsized to accommodate the increased solids loading.

To account for 90.0 percent reduction of SO<sub>2</sub> in the CFB boiler using LI, the CUECost “user specified coal” option was used by inputting coal parameters for western and Midwestern bituminous coals and TDF adjusted to reduce the coal sulfur content by 90.0 percent.

The cost for additional limestone injection was estimated based on the increased cost of limestone for the increased calcium to sulfur ratio necessary for the increased SO<sub>2</sub> reduction and the increased waste generated by the increased limestone usage and SO<sub>2</sub> removal.

#### **1.2.7.2 SO<sub>2</sub>/H<sub>2</sub>SO<sub>4</sub>/HF Energy and Environmental Impacts**

Energy impacts for the FGD technologies are due to increased the pressure drop across the flue gas contactor (scrubber, absorber, or ductwork), lime/limestone handling/preparation, waste handling, and the operation of the wet ESP. The WFGD system combined with a wet ESP results in the greatest increase in energy requirements due to the higher increased pressure drop relative to the other control options and due to the much higher energy requirements for processing limestone versus lime.

The environmental impacts for the FGD technologies and ALI are dominated by the increase in solid waste. This increase is the highest with the ALI and DIFGD because the calcium utilization of these processes is much lower than for WFGD and SDFGD. Note, the WFGD produces a wet scrubber sludge, which could require special handling and disposal if the moisture content of the waste exceeds 10-15 percent due to operational problems.

Assuming no flue gas reheat, the WFGD will produce a saturated stack plume which would have a negative aesthetic impact and could produce fogging and icing conditions under certain meteorological conditions. This is not an issue with the other control options.

One advantage to the combination of wet FGD and wet ESP might be a slight decrease in emissions of F and H<sub>2</sub>SO<sub>4</sub> over the other SO<sub>2</sub> control options. However, quantification of this benefit is not feasible considering the low expected emissions of these pollutants under any of the SO<sub>2</sub> scenarios evaluated.

#### **1.2.8 Proposed BACT Limit for SO<sub>2</sub>, H<sub>2</sub>SO<sub>4</sub>, and F Emissions**

Based on the above analysis, ADM proposes LI at 90 percent overall SO<sub>2</sub>, H<sub>2</sub>SO<sub>4</sub>, and F emission control as BACT. The BACT selection rationale follows:

LI plus Wet FGD is rejected as BACT because of the:

- High incremental cost effectiveness of approximately \$28,000 per ton over LI+SDFGD, of approximately \$15,000 per ton over LI+DIFGD, and of approximately \$13,000 per ton over LI;
- Increased energy requirements over LI+SDFGD, LI+DIFGD, ALI, and LI; and
- Increased waste disposal requirements over LI+LSFGD, LI+DIFGD, and LI.

LI plus SDFGD is rejected as BACT because of the:

- High incremental cost effectiveness of approximately \$7,400 per ton over LI+DIFGD, and of approximately \$9,600 per ton over LI;
- Increased energy requirements over LI; and
- Increased waste disposal over LI.

LI plus DIFGD is rejected as BACT because of the:

- High incremental cost effectiveness of approximately \$11,000 per ton over LI;
- Increased energy requirements over LI; and
- Increased waste disposal over LI.

ALI is rejected as BACT because of the:

- High incremental cost effectiveness of approximately \$6,700 per ton over LI; and
- Increased waste disposal over LI.

Thus, ADM proposes BACT limits for SO<sub>2</sub>, H<sub>2</sub>SO<sub>4</sub>, and F of:

Pollutant	Emission Limit	Compliance Demonstration
SO <sub>2</sub>	188 lb/hour; use of limestone injection and baghouse as control	per boiler 30-day rolling average using continuous monitoring as required by NSPS Subpart Db;
H <sub>2</sub> SO <sub>4</sub>	7.2 lb/hour; use of limestone injection and baghouse as control	per boiler – compliance determined using USEPA reference Method 8; and
F	0.9 lb/hour; use of limestone injection and baghouse as control	per boiler – compliance determined using USEPA reference Method 13.

The emission rate for H<sub>2</sub>SO<sub>4</sub> and F are difficult to determine because the available information on H<sub>2</sub>SO<sub>4</sub> and F removals for different types of SO<sub>2</sub> control devices are highly variable. As such, Table 1-8 summarizing the H<sub>2</sub>SO<sub>4</sub> and F BACT limits identified for CFB boilers since 1992 is used as the basis for selecting the BACT emission limits for H<sub>2</sub>SO<sub>4</sub> and F.

ADM proposes limestone injection with baghouse control as BACT for H<sub>2</sub>SO<sub>4</sub> emissions. A review of Table 1-8, which presents the results of the RBLC review and review of other permits, shows that H<sub>2</sub>SO<sub>4</sub> permit limits range from 0.010 lb/MMBtu to 0.015 lb/MMBtu. ADM proposes a per boiler BACT limitation of 7.5 pounds per hour. This limit is equal to a H<sub>2</sub>SO<sub>4</sub> emission rate of 0.010 lb/MMBtu.

ADM proposes limestone injection with baghouse control as BACT for F emissions. A review of Table 1-8, which presents the results of the RBLC review and review of other permits, shows that F permit limits range from 0.0004 lb/MMBtu to 0.0053 lb/MMBtu. ADM proposes a per boiler BACT limitation of 0.9 pounds per hour. This limit is equal to a F emission rate of 0.0012 lb/MMBtu. This limit is consistent with a recent BACT emissions limit found in Table 1-8.

**Table 1-8.**  
**Summary of Emission Limits Identified in**  
**Recent BACT Determinations for CFB Boilers**

Company/Facility	RBLC ID	Permit Date	SO <sub>2</sub> Limit	H <sub>2</sub> SO <sub>4</sub> Limit	HF Limit
Enviropower	Benton, IL <sup>a</sup>	07/03/01	0.25 lb/MMBtu	No limit	9.6 tons/yr (0.0004 lb/MMBtu)*
Kentucky Mountain Power, LLC	Ary, KY <sup>a</sup>	05/04/01	0.13 lb/MMBtu	0.010 lb/MMBtu	0.0053 lb/MMBtu
JEA NORTHSIDE GENERATING STATION	FL-0178	7/14/1999	0.2 lb/MMBtu	No limit	No limit
ARCHER DANIELS MIDLAND COMPANY Decatur Units 9 & 10	IL-0060	12/24/1998	0.7 lb/MMBtu	No limit	No limit
ARCHER DANIELS MIDLAND COMPANY Cedar Rapids Unit 5	IA-0051	6/30/1998	0.36 lb/MMBtu	No limit	0.0012 lb/MMBtu
ARCHER DANIELS MIDLAND COMPANY Cedar Rapids Unit 6	IA-0046	6/30/1998	0.36 lb/MMBtu	No limit	0.0012 lb/MMBtu
TOLEDO EDISON CO. - BAYSHORE PLANT	OH-0231	6/20/1997	0.73 lb/MMBtu	No limit	No limit

**Table 1-8.**  
**Summary of Emission Limits Identified in**  
**Recent BACT Determinations for CFB Boilers (Continued)**

<b>Company/Facility</b>	<b>RBLC ID</b>	<b>Permit Date</b>	<b>SO<sub>2</sub> Limit</b>	<b>H<sub>2</sub>SO<sub>4</sub> Limit</b>	<b>HF Limit</b>
TOLEDO EDISON CO. - BAYSHORE PLANT	OH-0231	6/20/1997	0.6 lb/MMBtu	No limit	No limit
YORK COUNTY ENERGY PARTNERS	PA-0132	7/25/1995	0.25 lb/MMBtu	No limit	No limit
NORTHAMPTON GENERATING CO.	PA-0134	4/14/1995	0.129 lb/MMBtu	No limit	No limit
ARCHER DANIELS MIDLAND COMPANY Decatur Unit 8	IL-0058	8/11/1994	0.7 lb/MMBtu	No limit	No limit
ARCHER DANIELS MIDLAND COMPANY Decatur Unit 7	IL-0058	8/11/1994	0.7 lb/MMBtu	No limit	No limit
AES WARRIOR RUN, INC.	MD-0022	6/3/1994	0.21 lb/MMBtu	0.015 lb/MMBtu	No limit
FORT DRUM HTW COGEN FACILITY	NY-0070	3/1/1994	1.2 lb/MMBtu	No limit	No limit
NORTH BRANCH ENERGY PARTNERS LP	PA-0058	1/25/1993	0.49 lb/MMBtu	No limit	0.0014 lb/MMBtu
a- Not in RBLC. * Calculated.					

### 1.3 Particulate Matter and Lead Control Technology Review

This control technology review includes a BACT analysis for the control of PM, PM<sub>10</sub>, and Pb from the CFB boilers.

#### 1.3.1 Identification of Technically Practicability

The RBLC database was reviewed to identify PM/PM<sub>10</sub> and Pb emission controls for fluidized bed and other coal-fired boilers. Data from the RBLC for PM/PM<sub>10</sub> and Pb emissions from coal-fired boilers are summarized in Table 1-9. This data indicates that fabric filter/baghouses are the only control technology that has been applied for the control of PM/ PM<sub>10</sub> and Pb emissions from CFB boilers and other coal-fired boilers permitted under the PSD program since 1992. The range in emission limitations from the RBLC and other permits not in this database are 0.011 to 0.03 lb/MMBtu for PM/PM<sub>10</sub> and 0.000194 to 0.0023 lb/MMBtu for Pb.

**Table 1-9.**  
**Emission Limits and Controls for PM, PM<sub>10</sub> and Pb Identified**  
**in Recent BACT Determinations for CFB Boilers**

<b>Company/Facility</b>	<b>RBLC ID</b>	<b>Permit Date</b>	<b>PM/ PM<sub>10</sub> Limit (lb/MMBtu)</b>	<b>Pb Limit (lb/MMBtu)</b>	<b>Control</b>
Enviropower	Benton, IL <sup>a</sup>	07/03/01	0.015	No limit	Baghouse
Kentucky Mountain Power, LLC	Ary, KY <sup>a</sup>	05/04/01	0.015	0.000194	Baghouse
JEA NORTHSIDE GENERATING STATION	FL-0178	7/14/1999	No limit/ 0.011 (3-hour average)	No limit	Fabric Filter or ESP
ARCHER DANIELS MIDLAND COMPANY/	IL-0060	12/24/1998	0.025 / No limit	No limit	Fabric Filter



Decatur Units 9 & 10					
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**Table 1-9.  
Emission Limits and Controls for PM, PM<sub>10</sub> and Pb Identified  
in Recent BACT Determinations for CFB Boilers (Continued)**

<b>Company/Facility</b>	<b>RBLC ID</b>	<b>Permit Date</b>	<b>PM/ PM<sub>10</sub> Limit (lb/MMBtu)</b>	<b>Pb Limit (lb/MMBtu)</b>	<b>Control</b>
ARCHER DANIELS MIDLAND COMPANY/Cedar Rapids Unit 5	IA-0046	6/30/1998	0.015 /0.03 (3-hour average)	0.0002	Fabric Baghouse
ARCHER DANIELS MIDLAND COMPANY/Cedar Rapids Unit 6	IA-0051	6/30/1998	0.015/ 0.03 (3-hour average)	0.0002	Fabric Baghouse
TOLEDO EDISON CO. – BAYSHORE PLANT	OH-0231	6/20/1997	0.025 / No limit	No limit	Fabric Filter
YORK COUNTY ENERGY PARTNERS	PA-0132	7/25/1995	No limit / 0.011	No limit	Fabric Filter with Rytan Bags
NORTHAMPTON GENERATING CO.	PA-0134	4/14/1995	No limit / 0.01	No limit	Fabric Filter
ARCHER DANIELS MIDLAND COMPANY	IL-0058	8/11/1994	0.025 / No limit	No limit	Fabric Filter
ARCHER DANIELS MIDLAND COMPANY	IL-0058	8/11/1994	0.025 / No limit	No limit	Fabric Filter
AES WARRIOR RUN, INC.	MD-0022	6/3/1994	0.015 / No limit	No limit	Fabric Filter
FORT DRUM HTW COGEN FACILITY	NY-0070	3/1/1994	0.05	No limit	Fabric Collector
ARCHER DANIELS MIDLAND COMPANY	IA-0025	8/3/1993	No limit / 0.03 (3-hour average)	No limit	Fabric Filter
NORTH BRANCH ENERGY PARTNERS LP	PA-0058	1/25/1993	No limit / 0.02	0.0023	Fabric Collector (None listed for Pb)
a- Not in RBLC.					

### **1.3.2 CFB Boiler PM/PM<sub>10</sub> Control Alternatives**

The most prevalent technologies, which have been used to control PM emissions from coal-fired boilers, include electrostatic precipitators (ESPs), wet scrubbers, mechanical collectors, and fabric filter/baghouses (baghouses).

#### **1.3.2.1 Electrostatic Precipitators**

ESPs are rarely used on CFB boilers using limestone injection for SO<sub>2</sub> control because the use of a baghouse significantly increases the achievable SO<sub>2</sub> control using limestone injection. This occurs because as the flue gas passes through the filter cake, additional SO<sub>2</sub> is removed by unreacted limestone and calcium oxide in the filter cake. The capture of particulate matter using an ESP does not provide this increase in SO<sub>2</sub> removal. Additionally, due to the high resistivity of the PM, which is predominately calcium oxide and calcium sulfate, very large ESP plate area would be required to match the collection efficiency of a baghouse making the use of an ESP more costly than a baghouse. Use of an ESP before or after a baghouse would have no measurable benefit (actually, if placed upstream of the baghouse, it could reduce the baghouse performance) due to the very high particulate removal capability of the fabric filter baghouse.

#### **1.3.2.2 Wet scrubbers and Mechanical Collectors**

Wet scrubbers are not used for PM controls on CFB boilers because of their lower overall collection efficiency, higher capital and operating costs, and the significant waste disposal and wastewater treatment issues that wet

scrubbing entails. Wet scrubbers can not be used in series with fabric filter baghouses to improve on PM control efficiency. If a wet scrubber is used upstream of the baghouse, the saturation of the flue gas with water will result in plugging of the fabric filters due to the reaction of condensed moisture with the highly alkaline particulate matter (making concrete). There is no benefit to putting a wet scrubber downstream of the baghouse since wet scrubbers have higher emission rates of PM than baghouses due to entrained water droplets that evaporate to particulates.

Mechanical collectors, such as cyclones, are used on CFB boilers primarily for process reasons and secondarily for PM control reasons. The purpose of the solids disengagement section of the boiler is to circulate the solid material that exits the furnace to create the “circulating bed” process. This recirculation process significantly improves overall combustion efficiency and utilization of the limestone for capturing acid gases such as SO<sub>2</sub>. Secondarily, the solids disengagement section reduces the particulate loading to the fabric filter baghouses reducing the frequency that the bags need to be replaced.

#### **1.3.2.3 Fabric Filter Baghouses**

Baghouses have a number of inherent advantages when used for the control of fly ash from CFB boilers using limestone injection for acid gas control. These advantages include:

- High PM collection efficiencies as compared to other technologies;
- PM collection capability is not sensitive to typical fuel sulfur and limestone injection variabilities;
- Additional control of SO<sub>2</sub> and other acid gases due to the filtration of the flue gas through the alkaline filter cake; and
- High trace metal and hazardous air pollutant control efficiencies.

The primary disadvantage of baghouses relative to ESPs is the higher pressure drop across the baghouse resulting in increased fan power requirements for the system.

#### **1.3.2.4 Enhanced Performance of the SO<sub>2</sub> Control System**

In addition to very high levels of particulate matter and fine particulate matter control, the baghouse system also increases the performance of SO<sub>2</sub> control systems. This is because the baghouse functions by creating a filter cake on the bag. As the flue gas passes through the filter cake, additional SO<sub>2</sub> is removed by the filter cake when the filter cake includes unreacted alkaline materials such as calcium oxide and calcium hydroxide. Depending on the operating conditions of the baghouse, the fabric filter baghouse will remove 15 – 30% of the total SO<sub>2</sub> removed.<sup>1</sup> The same mechanism for reducing SO<sub>2</sub> emissions in the baghouse also helps reduce inorganic acid gas emissions, including hydrochloric acid (HCl) and hydrofluoric acid (HF) emissions.

#### **1.3.2.5 Enhanced Fine PM and Trace Metal Control**

Since baghouses are more efficient at removing fine particulate matter than other PM control systems, including ESPs. They also have higher trace metal and inorganic hazardous air pollutant control efficiencies as compared to ESPs and other PM control systems.

### **1.3.3 Control Technology Description and Control Hierarchy**

The PM removal efficiency of wet scrubbers, mechanical collectors, and ESPs would be less than the removal efficiency of fabric filtration for CFB boilers using limestone injection for SO<sub>2</sub> control. Additionally, these other control technologies offer no measurable benefit in increased PM control if placed upstream or downstream of a properly sized baghouse. As such, a fabric filter is the top performing control technology. The remainder of this section provides additional information on baghouse controls and identifies achievable emission levels.

A baghouse separates dry particles from the boiler flue gas by filtering the flue gas through a fabric filter. The components of a baghouse include fabric filters or “bags” as the filter media, a tubesheet to support the bags, a gas-tight enclosure, a mechanism to dislodge or clean accumulated dust from the bags, and a hopper to collect

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<sup>1</sup> Air Pollution Engineering Manual, Air & Waste Management Association, Library of Congress Catalog Number 91-46007, page 237.

accumulated fly ash. The flue gas enters the lower portion of the baghouse and passes through the bags with the particulate from the flue gas collecting on either the inside or outside of the bags depending on the cleaning technique. Baghouses are compartmentalized to allow cleaning of one compartment at a time and to provide for maintenance and repair. When the pressure drop across a compartment increases to a preset limit, due to buildup of ash on the bags, the filter cake collected on the bag is removed by placing that compartment in the cleaning mode.

As the flue gas flows through the fabric filter, a layer of accumulated fly ash, referred to as the “filter cake”, builds up on the fabric. The primary filtering media is actually this filter cake, rather than the fabric itself. As this layer of ash grows, the pressure drop across the bag increases until a maximum set point is achieved. At this point, the bag is cleaned. The evolution of baghouse design has included several methods for cleaning the bag, including reverse air, reverse air with mechanical shakers, and pulse jet. In each of these baghouse types, the particulate removed from the bags by the cleaning process is collected in hoppers below the filter bags.

The four most stringent PM/PM<sub>10</sub> emission limitations for CFB boilers identified as BACT in Table 1-10 are summarized below (in lb/MMBtu).

**Table 1-10. Most Stringent CFB PM/PM<sub>10</sub> BACT Limits**

<b>Company</b>	<b>Limit (lb/MMBtu)</b>
Jacksonville Electric	0.011 <sup>1</sup>
York County Energy	0.011
Northampton Gen. Co.	0.011
AES Warrior Run	0.015

The York County Energy project was never constructed/operated. This leaves two emission levels to evaluate as BACT:

- 0.011 lb/MMBtu; and
- 0.015 lb/MMBtu.

#### **1.3.4 Impacts Analysis for PM, PM<sub>10</sub>, and Pb Emissions**

Because fabric filter/baghouse technology is required to meet the NSPS requirement, the impact analysis focuses on evaluating the environmental, energy, and economic impacts of various levels of control achievable using baghouse technology. Table 1-11 presents the impacts of two levels of PM/PM<sub>10</sub> control using baghouse technology. The CUECost Model was used to estimate the cost of the baghouse scenarios.

<sup>1</sup> JEA Northside Generating Station Permit No. 0310045-003-AC (PSD-FL-265); PM<sub>10</sub> per RM 201 or 201A .

**Table 1-11.  
Economic, Energy, and Environmental Impacts of Baghouse Technology**

<b>BAGHOUSE CONTROL LEVEL, lb/MMBtu*→</b>	<b>0.011</b>	<b>0.015</b>
<b>ECONOMIC IMPACTS</b>		
<b>Total Capital Requirement:</b>	\$9,788,298	\$8,798,163
<b>Annual Fixed O&amp;M Costs:</b>	\$448,848	\$403,445
<b>Annual Variable O&amp;M Costs:</b>	\$555,544	\$169,288
<b>Capital Recovery Costs:</b>	\$2,182,790	\$1,961,990
<b>Total Annual Costs:</b>	\$3,187,183	\$2,534,723
<b>Cost Effectiveness versus 0.015 lb/MMBtu:</b>	\$49,654	
<b>ENERGY IMPACTS</b>		
<b>MMBtu/hr Boiler Efficiency Penalty versus 0.015:</b>	1.9	Baseline
<b>ENVIRONMENTAL IMPACTS</b>		
<b>Tons Annual PM/PM<sub>10</sub> Reduction below 0.015:</b>	13	0
*Filterable particulate matter. <b>Note: All calculations are on a per boiler basis.</b>		

A review of the incremental impacts of reducing the PM/PM<sub>10</sub> emission limit from 0.015 lb/MMBtu to 0.011 lb/MMBtu follows.

#### **1.3.4.1 Baghouse Economic Impacts**

The incremental cost impacts of reducing the PM/PM<sub>10</sub> emission limit from 0.015 lb/MMBtu to 0.011 lb/MMBtu are:

- Increased Capital Requirement: ..... \$990,126
- Increased Annual Costs:..... \$652,460
- Incremental PM/PM<sub>10</sub> Reduction: ..... 13 tpy
- Incremental PM/PM<sub>10</sub> Cost Effectiveness:..... \$49,654

The design/cost difference between the two options is the use of different air-to-cloth ratios (1.75 for the 0.011 lb/MMBtu case and 3.5 for the 0.015 lb/MMBtu case) and different fabric material (Ryton for the 0.011 lb/MMBtu case and fiberglass for the 0.015 lb/MMBtu case).

#### **1.3.4.2 Baghouse Energy and Environmental Impacts Analysis**

As shown in Table 1-11, the incremental energy impacts of reducing the PM/PM<sub>10</sub> emission limit from 0.015 lb/MMBtu to 0.011 lb/MMBtu are small. The difference is due to the increased power required for rapping/pulsing more bags. There are no adverse environmental impacts between the two baghouse options. There will be an unquantifiable benefit to the lower emission limit with respect to lower emissions of particulate hazardous pollutants, such as Pb.

#### **1.3.5 Proposed BACT Limits for PM, PM<sub>10</sub>, and Pb Emissions**

Based on the information presented in this analysis, ADM proposes the use of a baghouse as BACT for PM/PM<sub>10</sub> and Pb emissions from the CFB boilers. A baghouse was selected as BACT because this technology has the ability to achieve the lowest PM and PM<sub>10</sub> emission rates of the available technologies, and because this technology is the only control technology applied to CFB boilers in recent BACT determinations.

The lowest PM/PM<sub>10</sub> emission limits of 0.011 lb/MMBtu is not proposed as BACT due to the very high incremental cost effectiveness of approximately \$50,000 per ton over baghouse with an emission limit of 0.015 lb/MMBtu. Eliminating the highest emissions limit of 0.011 lb/MMBtu as BACT based on economic impacts leaves the PM/PM<sub>10</sub> emission limit of 0.015 lb/MMBtu as the next highest control option. Thus, 11.3 pounds per hour per unit is proposed as BACT because this option has acceptable economic, energy, and environmental impacts. Compliance with this limit will be demonstrated using USEPA reference method 5 or 201. For well controlled combustion sources, the condensable fraction of PM/PM<sub>10</sub> emissions is generally about equal to the filterable PM<sub>10</sub> fraction (i.e., the PM<sub>10</sub> is 50% condensable and 50% filterable). For purposes of this BACT analysis, ADM proposes a filterable PM limit of 0.015 lb/MMBtu and a total PM<sub>10</sub> limit (filterable and condensable) of 0.025 lb/MMBtu based on compliance testing using USEPA reference methods 5 and 201/202.

The proposed BACT limit for Pb is difficult to determine because the available information on the Pb contents of the proposed solid fuels and limestone are not well known particularly with respect to other permitted CFB boiler projects. As such, based on the RBLC review results in Table 1-9, a BACT emission limit for Pb of 0.15 pounds per hour per unit is proposed with compliance measured using USEPA reference method 12. This limit is equal to a Pb emission rate of 0.0002 lb/MMBtu, which is consistent with the most recent BACT Pb emission limits found in Table 1-9.

## **1.4 CO and VOC Control Technology Review**

CO and VOC are emitted from the CFB boiler as a result of incomplete fuel combustion. Incomplete combustion also leads to emissions of particulate matter, and hazardous organic compounds. Therefore, the most direct approach for reducing CO and VOC emissions (and other related pollutants) is to improve combustion. This chapter includes a review of CO and VOC emission controls and limitations applied to other similar units.

### **1.4.1 Identification of Technically Feasible Controls**

The technologies used to control CO and VOC emissions from fluidized bed and other coal-fired boilers were first reviewed using the RBLC database. Data from the RBLC for CO and VOC emissions from coal-fired boilers are summarized in Table 1-12. This data indicates that good combustion control is the only control technology that has been applied for the control of CO and VOC emissions from CFB boilers and other coal-fired boilers recently permitted under the PSD program.<sup>1</sup> The range in emission limitations from the RBLC and other permits not in this database are 0.15 to 0.27 lb/MMBtu for CO and 0.004 to 0.032 lb/MMBtu for VOCs.

The only other technology capable of reducing CO and VOC emission rates below those obtained through good combustion control is an oxidation catalyst. However, while oxidation catalysts have been used to reduce CO and VOC emissions from natural gas and oil-fired combustion turbines, oxidation catalysts have not been used for CFB or other solid fuel-fired boiler applications.

### **1.4.2 Control Technology Description and Control Hierarchy**

#### **1.4.2.1 Oxidation Catalysts**

Oxidation catalysts can be used to reduce CO and VOC emissions as a post combustion control system. As noted above, while oxidation catalysts have been used to reduce CO and VOC emissions from natural gas and low sulfur, oil-fired combustion turbines, oxidation catalysts have not been used for CFB or other solid fuel-fired boiler applications.

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<sup>1</sup> In Table 1-12, "good combustion practices" and "combustion controls" all mean good combustion control.

The typical oxidation catalyst for CO is a rhodium or platinum (noble metal) catalyst on an alumina support material. This catalyst is installed in an enlarged duct or reactor with flue gas inlet and outlet distribution plates. Acceptable catalyst operating temperatures range from 400 - 1250 °F, with the optimum temperature range being 850 - 1,100 °F. Below 600°F, a greater catalyst volume would be required to achieve the same reduction. To achieve this temperature range in the CFB boilers, the catalyst would need to be installed in the boiler before the economizer. However, installation of the catalyst in this section of the boiler would result in rapid poisoning and deactivation of the catalyst by sulfur containing compounds and plugging of the active catalyst sites with particulates due to the high dust loading prior to fabric filtration. For this reason, catalytic oxidation of CO and VOC is not technically feasible for CFB boilers.

#### **1.4.2.2 Good Combustion Control**

Combustion controls generally include the following:

- High Temperatures;
- Sufficient Excess Air;
- Sufficient Residence Times; and
- Good Air/Fuel Mixing.

As with other types of fossil fuel-fired boilers, combustion control is the most effective means for reducing CO and VOC emissions from CFB boilers. Combustion efficiency is often related to the three “T’s” of combustion: Time, Temperature, and Turbulence. These components of combustion efficiency are designed into the CFB boiler to maximize fuel efficiency and reduce operating costs. Therefore, combustion control is accomplished primarily through boiler design and operation.

During operation, combustion is controlled by regulating fuel flow and excess air in the combustion section. Primary air is distributed through an air distributor to fluidize the bed. Normally, the amount of primary air is maintained below the stoichiometric requirement. Thus, the fuel is initially combusted under fuel-rich conditions. Secondary air is introduced above the bed in the freeboard area. The secondary air brings the total amount of combustion air up to the level needed to achieve complete combustion and minimize emissions of CO and VOCs.

Changes in excess air affect the availability of oxygen and combustion efficiency. Very low or very high excess air levels will result in high CO and VOC formation, and can also affect NO<sub>x</sub> formation. Increased excess air levels will reduce the emissions of CO and VOCs up to the point that so much excess air is introduced that the overall combustion temperatures begin to drop significantly. If combustion temperatures drop significantly, then boiler efficiency and steam temperatures are also negatively affected. Although lower combustion temperatures can reduce the formation of thermal NO<sub>x</sub>, the in-bed temperature reduction reduces SO<sub>2</sub> removal performance of in-bed limestone control and reduces NO<sub>x</sub> removal performance of SNCR control. CFB boilers operate within a narrow range of excess air levels due to these interrelationships.

#### **1.4.3 CO and VOC Control Hierarchy**

Based on the above review, good combustion control is the only technically feasible control option for CO and VOC. The following discussion presents the rationale for the proposed BACT limits for CO and VOC using good combustion control.

#### **1.4.4 Proposed BACT Limit for VOC Emissions**

Based on the information presented above, ADM proposes good combustion control as BACT for VOC emissions. Based on review of VOC emission limitations currently established for similar facilities, ADM proposes a per boiler BACT limitation of 5.3 pounds per hour. This limit is equal to a VOC emission rate of 0.007 lb/MMBtu, and would apply at all times and all loads other than during startup, shutdown, and malfunction conditions. This limit is consistent with the most recent BACT VOC emission limits found in Table 1-12, which range from 0.004 to 0.032 lb/MMBtu. Compliance with this limit will be demonstrated using USEPA reference method 25.

#### 1.4.5 Proposed BACT Limit for CO Emissions

Based on the information presented above, ADM proposes good combustion control as BACT for CO emissions. Based on review of CO emission limitations currently established for similar facilities, ADM proposes a per boiler BACT limitation of 75 pounds per hour for a 24-hour block average. This limit is equal to a full load CO emission rate of 0.10 lb/MMBtu, and would apply at all times and all loads other than during startup, shutdown, and malfunction conditions. This limit is consistent with the most recent BACT CO emission limits found in Table 1-12, which range from 0.10 to 0.25 lb/MMBtu. A 24-hour block averaging time using a CO continuous monitor is proposed to account for load changes and associated process adjustments to remain in compliance with NO<sub>x</sub> emission limits.

**Table 1-12. Emission Limits and Controls for CO and VOC Identified in Recent BACT Determinations for CFB Boilers**

Company/Facility	RBLC ID	Permit Date	CO Limit	VOC Limit	Control
Enviropower	Benton, IL <sup>a</sup>	07/03/01	0.27 lb/MMBtu	0.007 lb/MMBtu	None listed
Southern Illinois Power Cooperative, Marion Power Station	IL <sup>a</sup>	05/16/01	0.15 lb/MMBtu*	No Limit	Combustion Controls
Kentucky Mountain Power, LLC	Ary, KY	05/04/01	0.27 lb/MMBtu	0.0072 lb/MMBtu	Good Combustion Practice
JEA NORTHSIDE GENERATING STATION	FL-0178	7/14/1999	0.127 lb/MMBtu* (24-hour block average)	0.0051 lb/MMBtu* (3-hour block average)	Good Combustion Practices
ARCHER DANIELS MIDLAND COMPANY/ Decatur Units 9 & 10	IL-0060	12/24/1998	0.1 lb/MMBtu	0.032 lb/MMBtu	Good Combustion Practices
ARCHER DANIELS MIDLAND COMPANY/Cedar Rapids Unit 5	IA-0046	6/30/1998	0.15 lb/MMBtu (3-hour average)	0.0072lb/MMBtu (3-hour average)	Combustion Control
ARCHER DANIELS MIDLAND COMPANY/Cedar Rapids Unit 6	IA-0051	6/30/1998	0.15 lb/MMBtu (3-hour average)	0.0072lb/MMBtu (3-hour average)	Combustion Control
TOLEDO EDISON CO. - BAYSHORE PLANT	OH-0231	6/20/1997	0.13 lb/MMBtu	No limit	Good Combustion
YORK COUNTY ENERGY PARTNERS	PA-0132	7/25/1995	No limit	0.004 lb/MMBtu	Combustion Control
NORTHAMPTON GENERATING CO.	PA-0134	4/14/1995	0.15 lb/MMBtu	0.005 lb/MMBtu	None listed
ARCHER DANIELS MIDLAND COMPANY	IL-0058	8/11/1994	No limit	0.032 lb/MMBtu	Good Combustion Practices
ARCHER DANIELS MIDLAND COMPANY	IL-0058	8/11/1994	0.1 lb/MMBtu	0.032 lb/MMBtu	Good Combustion Practices
AES WARRIOR RUN, INC.	MD-0022	6/3/1994	0.15 lb/MMBtu	No limit	Combustion Controls
FORT DRUM HTW COGEN FACILITY	NY-0070	3/1/1994	0.25 lb/MMBtu	No limit	No Controls
ARCHER DANIELS MIDLAND COMPANY	IA-0025	8/3/1993	0.2 lb/MMBtu (3-hour average)	No limit	Good Combustion Practices
NORTH BRANCH ENERGY PARTNERS LP	PA-0058	1/25/1993	0.15 lb/MMBtu	0.01 lb/MMBtu	None listed for CO, Good Operating Practice for VOC Control

a- Not in RBLC.

\*Calculated Value.



## 1.5 Boiler MACT and BACT for HAPs

The CFB boiler stack will be a source of hazardous air pollutants (HAPs). The potential HAP emissions from the proposed CFB boiler for the Columbus facility are summarized below in Table 1-13.

**Table 1-13. Estimated HAP Emissions From the CFB Boiler Stack<sup>1</sup>**

Hazardous Air Pollutant	Tons per Year (for 2 boilers)	Emission Basis
Hydrochloric acid	131.4	MACT compliance
Hydrofluoric acid	7.6	BACT for F
Mercury	<0.2	MACT compliance
Trace Elements (arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium)	0.6	MACT compliance
Organic HAPs (PCDD/PCDFs, PAHs, and organic HAPs) <sup>2</sup>	3.2	MACT compliance

This section addresses the control of HAP emissions relative to:

- The recently proposed National Emissions Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters<sup>3</sup>;
- BACT for HAPs as prescribed by N.A.C. Title 128, Chapter 27; and
- BACT as proposed in Sections 1.1 through 1.4.

On January 13, 2003 the USEPA proposed maximum achievable control technology (MACT) emission limits and standards for industrial boilers such as the proposed CFB boiler. The proposed CFB boilers each meet the MACT applicability classification as a New, Solid Fuel, Large Unit. As such, the proposed boilers must comply with the final MACT limits and standards when the rule is finalized (or upon startup if the rule is already final).

BACT for HAPs is a requirement of the Nebraska Administrative Code pursuant to Title 129, Chapter 27.

Additionally, pursuant to the U.S. EPA Administrator's decision in the North County Resource Recovery Associates, PSD Appeal No. 85-2, a PSD permitting authority (NDEQ) should consider the effects of a control alternative on toxic or hazardous pollutants. The ability of a given control alternative to control HAP emissions must be evaluated and HAP emissions resulting from the given control technology should be considered in making the BACT decision.

The expected HAP emissions from the combustion of 20% tire derived fuel would be similar to 100% coal-firing.<sup>4</sup> With the firing of TDF in a CFB boiler, it is expected the metals will be condensed particulates before entering the fabric filters and will be controlled at levels greater than 99.9%. Because the combustion residence time in CFB

<sup>1</sup> For purposes of this analysis, HAP refers to those compounds identified in N.A.C. Title 129, Appendix II.

<sup>2</sup> Sum of organic HAPs identified in AP-42 Tables 1.1-12, 1.1-13 and 1.1-14.

<sup>3</sup> Federal Register/Vol. 68, No. 8/Monday, January 13, 2003/Proposed Rules. Also, referred to as Maximum Achievable Control Technology standards.

<sup>4</sup> The report "Test Burning of Tire-Derived Fuel in Solid Fuel Combustors" shows toxic metal emissions were less and dioxin/furan emissions were the same (not detectable) when firing 20% TDF and 80% coal relative to 100% coal-firing. The report was prepared for Illinois Department of Energy and Natural Resources, July 22, 1991, Revision 2 (ILENR/RR-91/16).

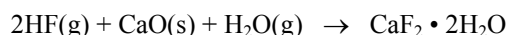
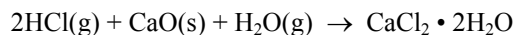
boilers is much greater than for stoker boilers and because of the reactivity of the bed materials with respect to chlorides and fluorides, CFB boilers would be expected to generate much lower levels of POMs, CO, VOCs, and dioxin/furans than stoker boilers. As such, the combustion of 20% TDF will not increase the emissions of HAPs over that of coal combustion.

Wet scrubber and/or spray dryer techniques (in addition to limestone injection) offer greater control or removal of vaporous organic compounds and acid gases. Spray dryers have a wet section, which lowers the flue gas temperature to about 160°F followed by a baghouse. The lower flue gas temperatures results in greater condensation/absorption of gaseous organics and metals and subsequent collection in the baghouse. Wet scrubbers are more effective than spray dryers because the flue gas temperature is lower (130°F) than with spray dryers. The lower temperature allows greater condensation of vapor phase metals and organics with subsequent removal as particulates. However, the cost effectiveness of spray dryers and wet scrubbers for HAP emissions is enormous. For example, using an emissions factor for beryllium of 81 lb/10<sup>12</sup> Btu (AP-42 Table 1.1-17 for pulverized coal), the cost effectiveness of wet scrubbing would be 3,000 times greater than for SO<sub>2</sub> control (0.25lb/MMBtu divided by 0.000081 lb/MMBtu = 3,086) or approximately three million dollars per ton.<sup>1</sup>

Based on economic feasibility, ADM proposes control/minimization of the federally regulated HAPs through the use of combustion control, limestone injection, and fabric filtration (baghouse) consistent with the proposed PSD-BACT decisions for CO, VOC, PM, Pb, and F and consistent with MACT. The following sections describes the BACT/MACT limits and standards for HCl, HF, trace element HAPs (arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium), and organic HAPs.

### 1.5.1 Hydrochloric acid and Hydrofluoric Acid Emissions

Hydrochloric acid (HCl) and hydrofluoric acid (HF) are acid gas emissions resulting from chlorine and fluorine which occur in relatively low concentrations in the fuels and limestone. These emissions will be effectively controlled by unreacted lime in the baghouse. The following overall reactions are the primary mechanisms for the removal of HCl and HF gases:



HCl and HF emissions are highly reactive, so the removal efficiency of these reactions is expected to be at least as high as the removal efficiency for sulfur dioxide.

HCl emissions are based on compliance with the recently promulgated National Emissions Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters.<sup>2</sup> The rule contains an HCl maximum achievable control technology (MACT) limit of 0.02 lb/MMBtu for new, solid fuel, large units such as the proposed Columbus CFB boilers. The proposed HCl MACT limit converts to an annual average emission rate of 15 pounds per hour and 65.7 tons per year for each of the proposed CFB boilers. ADM proposes to demonstrate compliance with these limits using USEPA reference method 26 or 26A.

HF emissions are based on the PSD-BACT limit discussed previously because specific limits were not proposed in the National Emissions Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters. The proposed HF BACT limit converts to an annual average emission rate of 0.9 pound per hour and 3.9 tons per year for each of the proposed CFB boilers. ADM proposes to demonstrate compliance with these limits using EPA reference method 13.

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<sup>1</sup> From Table 1-7 the incremental cost effectiveness of WFGD and SDFGD over LI at 0.25 lb SO<sub>2</sub>/MMBtu is approximately \$10,000 per ton. HAP cost effectiveness would be \$10,000 \* (0.25/.000081) or approximately \$3,100,000 per ton of HAP removed assuming 90% control of HAP.

<sup>2</sup> See TABLE 1, Federal Register/Vol. 69, No. 176/Monday, September 13, 2004.

### **1.5.2 Trace Element HAP Emissions**

Trace element HAP emissions include a number of trace metals and elements which are naturally occurring in the coal and limestone. During combustion, these trace elements are volatilized and may be emitted as inorganic oxides or elemental forms. Most of the metals and their compounds will remain in a solid or liquid form in CFB boilers. Beryllium, cadmium, arsenic, and mercury will probably exist in the combustion zone in a vapor/gaseous form. Arsenic and cadmium will return to a solid form by the time they reach the cooler (approximately 300°F) environment of the baghouse. Chlorine released in the combustion chamber will react with calcium to form a solid material. A baghouse is the most efficient method for control of solid particles (see previous PSD-BACT analysis for particulate matter, Section 1.3). Some of the mercury and beryllium compounds will exist as a vapor or gas in the baghouse and will not be as effectively removed as the other condensed pollutants.

The proposed trace element emission limits are based on compliance with the recently proposed National Emissions Standards for Hazardous Air Pollutants for Industrial/Commercial/ Institutional Boilers and Process Heaters.<sup>1</sup> If promulgated, the rules contain a MACT limit of 0.0001 lb/MMBtu for new, solid fuel, large units applicable to the proposed Columbus CFB boilers. The proposed MACT limit converts to an annual average emission rate of 0.075 pound per hour and 0.33 tons per year for each of the proposed CFB boilers. ADM proposes to demonstrate compliance with these limits using USEPA reference method 29.

### **1.5.3 Mercury Emissions**

Mercury (Hg) emissions will occur from this facility as a result of trace levels of this contaminant in coal and limestone. During combustion, mercury is volatilized and may be emitted as inorganic oxides and in the elemental form. Mercury emissions are based on compliance with the recently proposed National Emissions Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters. If promulgated, the rules contain a MACT limit of 0.000003 lb/MMBtu for new, solid fuel, large units applicable to the proposed Columbus CFB boilers. The proposed MACT limit converts to an annual average emission rate of 0.0023 pound per hour and 0.0099 tons per year for each of the proposed CFB boilers. ADM proposes to demonstrate compliance with these limits using USEPA reference method 29.

### **1.5.4 Trace Organic HAP Emissions**

Trace organic HAP emissions may be emitted from each boiler as a result of incomplete combustion. Potential emissions for approximately 60 organic HAP compounds are estimated based on emission factors from U.S. EPA's AP-42 (September 1998) Compilation of Air Pollutant Emission Factors, Section 1.0, as follows:

- Table 1.1-12 Emission Factors for Polychlorinated Dibenzo-P-Dioxins (PCDDs) and Polychlorinated Dibenzofurans (PCDFs) from Controlled Bituminous and Subbituminous Coal Combustion;
- Table 1.1-13 Emission Factors for Polynuclear Aromatic Hydrocarbons (PAH) from Controlled Coal Combustion; and
- Table 1.1-14 Emission Factors for Various Organic Compounds from Controlled Coal Combustion.

The best and simplest method of control of organic HAPs is the destruction of these compounds by incineration or combustion. High temperatures, an optimum amount of oxygen, and good mixing of the components involved are needed to ensure the destruction of organics. However, greater control of organics through higher bed combustion temperatures would be at the expense of increased emissions of other pollutants (e.g., SO<sub>2</sub>, NO<sub>x</sub>, and possibly metal emissions).

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<sup>1</sup> Includes arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium.

The proposed MACT limit for these compounds uses CO as a surrogate. This limit is 400 ppm CO at 3% oxygen monitored continuously.<sup>1</sup> Note, the proposed PSD-BACT limit for CO is 92 ppm.

## **1.6 Coal/Limestone/Ash Handling PM/PM<sub>10</sub>**

The proposed CFB boiler project includes numerous solids handling facilities for coal, limestone, and ash handling. These types of facilities generate both point and fugitive sources of particulate matter. Table 1-14 summarizes the particulate control measures identified for a number of coal-fired boiler projects identified through the RBLC review process.

### **1.6.1 Identification/Description of Technically Feasible Controls**

Particulate matter emissions generated from materials handling and storage operations are typically controlled by one or more strategies. Typical strategies include but are not limited to the following:

- Handling and storing bulk materials in a wet or semi-wet condition. These materials are considered "conditioned materials" and will typically have moisture contents greater than 3.5 percent.
- Direct application of water and/or chemicals to bulk materials for purposes of increasing moisture content and/or stabilizing small particles is considered a "Wet Suppression" technique.
- Indirect application of water to materials for purposes of knocking down fugitive dust once it is released from the operation is considered the use of "Water Sprays." This approach can be augmented by adding a dust suppressant chemical to the water which creates a crust on the surface of the solid material and remains much longer than water.
- Total or partial enclosure such as the use of buildings, conveyor covers, and silos. Also, pneumatic conveying of materials through pipes and ductwork.
- Wind breaks/guards to reduce or eliminate particulate emissions from wind erosion.
- Dust collection systems which collect and control particulate emissions from partial or totally enclosed operations with the use of an add-on baghouses.

The most stringent control technology is the total enclosure of the emissions unit or activity which is generating the particulate matter, coupled with a dust collection/ventilation system that uses a fabric filter to remove particulates from the ventilation air/gas. However, in many cases this approach is not practical based on either economic or safety reasons and the available control strategies must be implemented.

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<sup>1</sup> The proposed MACT for organic HAPs is good combustion. Good combustion control is defined by having less than 400 ppm CO in the boiler flue gases.

**Table 1-14.**  
**Emission Limits and Controls Identified in Recent BACT Determinations for CFB Boilers**  
**Coal/Limestone/Ash Handling Systems**

<b>Emission Source</b>	<b>Control Methods</b>	<b>Emission Limits</b>	<b>Reference</b>
Ship Unloading (shiphold, receiving hoppers and conveyors)	Conditioned Materials Water Spray Enclosures		RBLC ID FL-0178
Coal Railcar Unloading	Chemical Suppressant	95% control	RBLC ID IA-0067
Coal Stacker Conveyor & Transfer to Active Pile	Chemical Suppressant	95% control	RBLC ID IA-0067
Coal Conveyors and Transfer Points	Conditioned Materials Water Spray Enclosures Chemical Suppressant Enclosed & Baghouse	95% control 0.005 gr/dscf	RBLC ID FL-0178 RBLC ID IA-0067
Coal Storage (active/ inactive)	Conditioned Materials Water Spray Enclosures Chemical Suppressant Wind Fence	95/99% control	RBLC ID FL-0178 RBLC ID IA-0067 RBLC ID AK-0024
Coal Stackers/Reclaim	Conditioned Materials Water Spray Enclosures Chemical Suppressant	95% control	RBLC ID FL-0178 RBLC ID IA-0067
Coal Crusher	Conditioned Materials Enclosure & Baghouse		RBLC ID FL-0178
Boiler Building Coal/Limestone/Lime Silos	Enclosure & Baghouse	0.005 gr/dscf	RBLC ID FL-0178 RBLC ID IA-0067
Limestone Receiving/Conveying/Crushing/ Reclaim	Conditioned Materials Enclosures & Baghouse	0.01 gr/dscf	RBLC ID FL-0178
Limestone Pile	Conditioned Materials Water Sprays		RBLC ID FL-0178
Lime or Limestone Storage Silo	Baghouse	0.02 gr/dscf	RBLC ID AK-0024
Fly/Bottom Hoppers/Transfer to Silos	Enclosure & Baghouse	0.01 gr/dscf	RBLC ID IA-0051
Fly/Bottom Ash Silo Hydrators/Load-Out	Conditioned Materials Water Spray Enclosures		RBLC ID FL-1078
Paved Roads	Water wetting Sweeping	80% combined control	RBLC ID IA-0067
Unpaved Roads	Chemical suppressant	95% control	RBLC ID IA-0067 & AK-0024

#### **1.6.1.1 Enclosure**

Enclosures reduce particulate emissions by entirely containing the material preventing any release of particulates or by reducing the wind that can entrain small exposed particles. Enclosures are typically used to capture emissions from operations like as truck or rail car unloading such that the dust emitted can be collected and vented to a control device. The most common and most effective vent control is the fabric filter baghouse. The reduction in emissions from the decrease in wind velocity is expected to be up to 100 percent when compared to processes in the open.

The effectiveness of the enclosure is directly impacted by the degree to which the operation is enclosed. Totally enclosed buildings, such as the boiler building, crusher buildings, and conveyor transfer buildings, offer the highest degree of control. Partial enclosures, such as used for rail car and truck unloading, are less effective due to the openings required for the railcar and truck passage. The effectiveness of these types of enclosures can be increased through the use of doors or flexible curtains.

Other types of enclosures typically used for handling dry solids are silos, hoppers, bins, and conveyor covers. As is the case for building enclosures, the degree of control is proportional to the degree to which the operation is enclosed. However, in well controlled situations these types of devices are typically totally enclosed.

Solids transfer operations include gravity and pneumatic flow, conveying on belts, and bulldozers, front-end loaders and buckets or clamshell loaders. Pneumatic flow is always enclosed in pipes. All the other types of transfer operations can be conducted with or without enclosure.

Due to health and safety reasons, most enclosed operations require ventilation to remove the particulates generated by the operation. Also, pneumatic transfer operations result in ventilation of the pneumatic transfer gas/air. As discussed in section 1.3, there are a number of devices that are effective at removing particulates from gas streams such as ventilation air. These control devices include baghouses, electrostatic precipitators, and mechanical collectors such as cyclones. As is the case for the CFB boiler stack, the fabric filter baghouse is the most effective control device for removing coal, ash, and limestone particulates from ventilation and conveying air.

#### **1.6.1.2 Wet and Chemical Suppression**

Solid materials with higher moisture content generate less PM<sub>10</sub>. Some materials have high inherent moisture content while others can be controlled through the addition of water. Controlled emission factors are between 42 and 98 percent lower than the uncontrolled factors.<sup>1</sup>

The addition of moisture can be accomplished in two different ways. One way is to mix the water with the solid material increasing the moisture content of the entire material. The other way is to add water only to the exposed surface of the material being handled through the use of sprays. In either case, as the material dries, the effectiveness of the wet suppression decreases.

Chemicals can also be used to bind small particles in solid materials. Some of these chemicals are additives, such as surfactants, to water sprays which allow for a lower water application rate or develop a crust on the material surface. Other chemicals, such as oils, are added in place of water. Chemical suppressants are particularly effective at reducing emissions from inactive storage piles because undisturbed the chemical can remain effective for much longer periods of time than the one time use of water.

#### **1.6.1.3 Wind Breaks and Guards**

Another type of fugitive dust control is the use of wind breaks or guards. These controls reduce average wind speeds across storage piles and other exposed material surfaces, thereby reducing the amount of particulates becoming wind born and migrating offsite. Wind breaks can potentially reduce emissions by 50 to 80 percent.<sup>2</sup>

### **1.6.2 PM/PM<sub>10</sub> Control Hierarchy**

For process emissions control, the most effective control option is total enclosure with effective control of ventilation system gases with baghouses. Depending on the amount of material and the size of the operation to be controlled, total enclosure is not always economically practicable. Where total enclosure is not feasible, then the use of wet/chemical suppression can be highly effective. Least effective and lowest in cost is the use of partial enclosures and wind break/guards.

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<sup>1</sup> Pages 4-29 through 4-33 of CONTROL OF OPEN FUGITIVE DUST SOURCES, EPA-450/3-88-008.

<sup>2</sup> Page 4-26 of CONTROL OF OPEN FUGITIVE DUST SOURCES, EPA-450/3-88-008.

### 1.6.3 Impacts Analysis for PM/PM<sub>10</sub> Emissions

ADM proposes to use the highest level of control for particulate emissions and economic, environmental, and energy impact analyses were not developed.

### 1.6.4 Proposed BACT Limits for PM/PM<sub>10</sub> Emissions

ADM proposes enclosure with ventilation system vents control using baghouses as BACT for all solids handling systems. Particulate emissions from the baghouses will be controlled to 0.005 gr/dscf. Table 1-15 summarizes the particulate emission controls and emission limits proposed as BACT.

**Table 1-15.**  
**Proposed BACT Emission Limits and Controls**  
**CFB Boiler Project Coal, Limestone, and Ash Handling Systems**

<b>Emission Source</b>	<b>Control Methods</b>	<b>Emission Limits</b>
Coal Railcar Unloading (2 points)	Enclosed Rotary Car Dumper Vented to baghouses	95% control 0.005 gr/dscf
Coal Conveyor Transfer to Coal Storage, Coal Storage Dome & TDF and Biomass Stackout, Reclaim Tunnel from Dome	Enclosed conveyors Transfer in building/tower Vented to bag	95% control 0.005 gr/dscf
Coal Crusher Tower	Enclosed Vented to baghouse	95% control 0.005 gr/dscf
Powerhouse Building/Silos	Enclosed Vented to baghouse	95% control 0.005 gr/dscf
Limestone Receiving/Storage/ Transfer (4 points)	Enclosed Vented to baghouse	95% control 0.005 gr/dscf
Bottom Ash Collection/Transfer/Storage Silos (4 points)	Enclosed Vented to baghouse	95% control 0.005 gr/dscf
Fly Ash /Transfer/Storage (2 points)	Enclosed Vented to baghouse	95% control 0.005 gr/dscf
Cooling Towers (6 points)	drift eliminators designed to minimize total liquid drift	
Roads	Paved + Sweeping	

### 1.7 Cooling Tower BACT Analysis

ADM will install a new cooling tower to provide a source of cooling water for the CFB boilers. This cooling tower is a source of particulate matter emissions due to drift of cooling water containing dissolved solids. Chromium compounds will not be used in the cooling water, thus it is not a source of HAP emissions.

The BACT analysis for the CFB cooling tower provided below includes a description of the source and its emissions, identification of possible control technology options for reducing emissions, an assessment of the economic, environmental, and energy impacts associated with each option, and a determination of BACT for the source.

### 1.7.1 Source Description

Cooling capacity will be needed for the Columbus CFB boilers. Thus, ADM is planning to purchase and install a new cooling tower that can be used to provide cooling water in this area. The cooling tower design specifications that affect emissions are presented in Table 1-16. Each cooling tower cell will be equipped with a high-efficiency drift eliminator.

**Table 1-16. Columbus CFB Cooling Tower Design Specifications**

Parameter	Value	Units
Type	6-cell, forced draft	---
Design flow rate, total	30,000	Gallons per minute
Max Total Dissolved Solids	2,500	ppmw

Cooling water will be pumped to the top of the tower, where it will be allowed to drop across a series of baffles within each cell. Fans at the top of the tower will draw air through the cascading water and then through a drift eliminator, before it is exhausted from the tower. A small fraction of the contacted water will escape as droplets (called drift) entrained in the exhausted air.

Each entrained droplet of cooling water contains dissolved solids (total dissolved solids or TDS). When the water evaporates, it leaves behind the TDS as particulate matter. As such, the cooling tower will have the potential to emit small amounts of PM and PM10.

### 1.7.2 Summary of Proposed Limits

ADM's proposed PM and PM10 BACT for the new CFB cooling towers is the installation of high-efficiency drift eliminators designed to reduce drift to 0.0005 % of total recirculating flow. Based on this drift loss factor, the design circulation rate, and the maximum projected TDS level, the estimated emissions from the CFB cooling towers are:

- 0.8 tons PM per year.
- 0.5 tons PM10 per year.

### 1.7.3 PM/PM10 Control Technology Review

This section presents ADM's BACT analysis for PM and PM10 emissions from the CFB cooling towers. The following subsections address each of the required five steps in the BACT analysis process.

#### Step 1: Identify Available Control Options

Based on the review of BACT databases, the most effective PM/PM10 control technology identified was use of mist eliminators (also known as drift eliminators) with various efficiency ratings. One additional control technology identified was the use of water treatment technology, in conjunction with a high efficiency drift eliminator. That



technology was listed as part of a Lowest Achievable Emission Rate (LAER) limit for PM<sub>10</sub> for Wallula Generation, LLC in Washington state.

### **Step 2: Eliminate Technically Infeasible Control Options**

The installation of high efficiency drift eliminators and the use of water treatment technology to further reduce TDS in the cooling water are considered available and technically feasible control technologies. The only feasible TDS removal technology identified was enhanced demineralization using softeners and ion exchange beds to remove additional TDS from the cooling water makeup stream. Both reverse osmosis and distillation were rejected due to their high energy requirements and high annual operating costs relative to ion exchange based demineralization. Although demineralization was considered feasible and is evaluated in this analysis, the substantial additional cost of treating/disposing of byproduct sludge, spent resin and wastewater generated by the process was not included in the cost evaluation. A TDS removal efficiency of 80% was assumed for the demineralization process.

### **Step 3: Rank Technically Feasible Control Options**

A summary of the most recent top 10 performing cooling tower PM/PM<sub>10</sub> control technologies is presented in Table 1-17. The most efficient drift eliminator-based limit shown is 0.0005% drift loss. As discussed, mist eliminators have been combined with water treatment for TDS removal to achieve lower PM and PM<sub>10</sub> emissions. For this analysis, the baseline emissions presume the use of drift eliminators designed for a drift rate of 0.005% of total recirculating flow. The 0.005% drift rate represents good engineering practice and ensures economical water conservation (i.e., to minimize water losses and makeup water requirements due to drift).

Based on the control technology precedents shown in Table 1-17, the following ranking of control technologies is proposed:

1. Use of mist eliminators designed for 0.0005% drift, with water treatment for removal of 80% of the TDS in the makeup water;
2. Use of mist eliminators designed for 0.0005% drift;
3. Use of baseline mist eliminators (0.005% drift) plus water treatment for removal of 80% of the TDS in the makeup water; and
4. Use of mist eliminators designed for 0.005% drift (baseline).

### **Step 4: Evaluate Technically Feasible Control Options**

Table 1-18 presents a summary of the cost impacts associated with the identified PM/PM<sub>10</sub> controls. ADM is proposing that PM and PM<sub>10</sub> BACT for the cooling tower be installation of high efficiency mist eliminators, designed to reduce drift to 0.0005% of total recirculating flow. This option was found to have an average cost effectiveness of \$5,334/ton PM<sub>10</sub> controlled. Based on a total capital investment of \$1.4 million for installing a high efficiency water demineralization plant to remove 80% of the TDS from approximately 500 gpm makeup water, the use of water treatment in combination with an ultra-high efficiency drift eliminator is not justified due to high average and incremental cost effectiveness values of \$44,000 and \$479,000 per ton of PM<sub>10</sub> respectively.

### **Step 5: Establish BACT**

Because PM/PM<sub>10</sub> emissions associated with cooling tower drift cannot be measured, ADM is proposing a work practice standard as BACT. This work practice standard is the installation of an ultra high-efficiency drift eliminators designed for 0.0005% drift.

**Table 1-17. Summary of RBLC Data for Cooling Tower PM/PM10 Emissions**

RBLC ID	Company/Facility	Permit Date	PM <sub>10</sub> Limit	Units	Control Device
*AZ-0049	LA PAZ GENERATING FACILITY	9/4/2003	0.0005	% of drift	Drift Eliminators
NY-0093	TIGEN-NASSAU ENERGY CORPORATION	3/31/2005	0.0005	% of drift	Drift Eliminators
*NV-0036	TS POWER PLANT	5/5/2005	0.0005	% of drift	Drift Eliminators
IA-0067	MIDAMERICAN ENERGY COMPANY	06/17/2003	0.0005	% of drift	Mist Eliminators
WA-0291	WALLULA GENERATION, LLC	01/03/2003	0.0005	% of drift	PM <sub>10</sub> LAER is Mist Eliminators plus water pretreatment
TX-0295	SOUTH TEXAS ELECTRIC COOPERATIVE INC	01/17/2002	0.0005	% of drift	Drift Eliminators
NJ-0044	MANTUA CREEK GENERATING FACILITY	06/26/2001	0.0005	% drift rate	Drift Eliminator
MD-0032	DICKERSON	11/5/2004	0.001	% of drift	Drift Eliminators
AR-0070	GENOVA ARKANSAS I, LLC	08/23/2002	0.001	% of drift	Drift Eliminators
OK-0056	MUSTANG POWER LLC	02/12/2002	0.001	% of drift	Drift Eliminators

\* Draft Determination.

**Table 1-18. Summary of Top-Down BACT Impacts Analysis Results for Cooling Tower PM**

Unit	Control Alternative	Limit	PM10 Emissions (TPY)	Emission Reductions (TPY)	Total Capital Cost (\$000)	Total Annualized Cost (\$000/yr)	Average Cost-Effectiveness (\$/ton PM10)	Incremental Cost Effectiveness (\$/ton PM10)	Environmental Impacts (Yes/No)	Energy Impacts (Yes/No)
New Cooling Tower, 120,000 gpm	High Eff. Mist Eliminator with TDS Removal System	0.0005% drift;80% TDS removal	0.1	5	\$1,407	\$199	\$44,000	\$479,000	Yes	Yes
	High Eff. Mist Eliminator	0.0005% drift	0.5	4	\$157	\$22	\$5,334	\$5,334	No	No
	Baseline Mist Eliminator with TDS Removal System	0.005% drift;80% TDS removal	0.9	4	\$1,354	\$191	\$51,986	\$51,986	Yes	Yes
	Baseline Mist Eliminator	0.005% drift	4.6	---	\$104	\$14.9	---	---	---	---

## **Appendix E - PSD-BACT Analysis for Biogas Vent**

## 1.0 INTRODUCTION

This document is a PSD Best Available Control Technology (BACT) analysis for the anaerobic digester biogas stream at ADM's Columbus Nebraska plant. It is being submitted as addenda to ADM's December 15, 2003 PSD permit application. This source has recently been identified by ADM as having H<sub>2</sub>S levels in the gas that are higher than previously measured. Since H<sub>2</sub>S is oxidized to SO<sub>2</sub> before it is vented, this BACT analysis addresses emissions of SO<sub>2</sub> associated with this stream.<sup>1</sup>

The approach used to evaluate BACT is the "top-down" methodology as required by EPA and documented in the Title 129, Chapter 19 discussion previously.

The remainder of this section describes the Columbus biogas system and presents the BACT analysis developed in accordance with the above methodology.

## 2.0 PROPOSED BACT LIMITS

ADM has completed a BACT analysis for the Columbus biogas vent and has identified the following emissions limit as BACT:

**Table 2-1. Proposed SO<sub>2</sub> BACT Limit**

Emission Point	Limit	Averaging Time	Test Method
Gluten Flash Dryer #1 (SV-16)	6.6 lb/hr	3-hr	USEPA Method 6c

The technical basis for this limit is presented in Section 4 of this report.

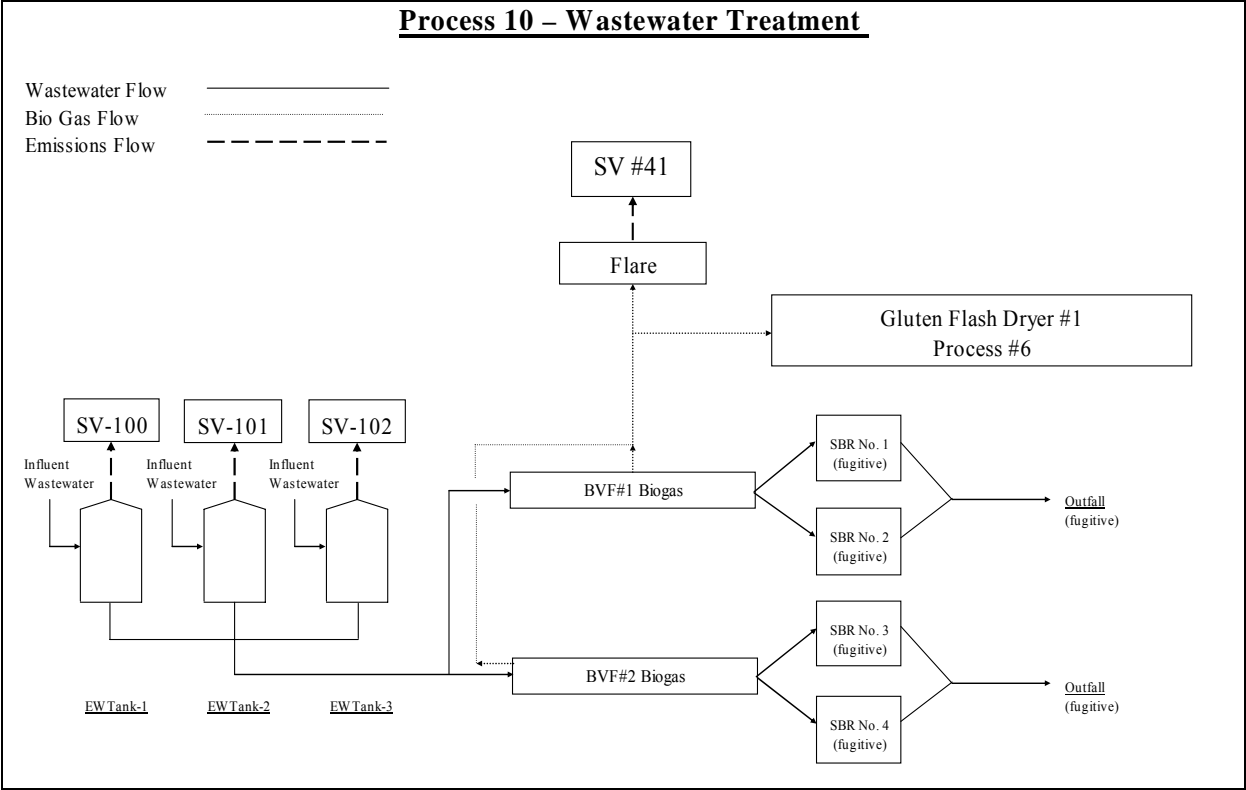
## 3.0 DIGESTER BIOGAS VENT DESCRIPTION

The wastewater treatment system at ADM's Columbus plant includes two anaerobic digesters which convert much of the organic material present in the influent wastewater to biogas (primarily methane and carbon dioxide with about 1 vol. % H<sub>2</sub>S). This biogas is collected and used in lieu of natural gas as fuel in Gluten Flash Dryer #1 (GFD #1). The exhaust from GFD #1 is processed through product recovery cyclones, treated by a wet scrubber to control emissions, and then exhausted through a stack. Biogas that is not combusted in GFD #1 is routed to an open flare where the H<sub>2</sub>S is oxidized to SO<sub>2</sub> before being exhausted to the atmosphere. The configuration of the wastewater treatment process and the gluten drying process are shown in Figures 1-1 and 1-2.

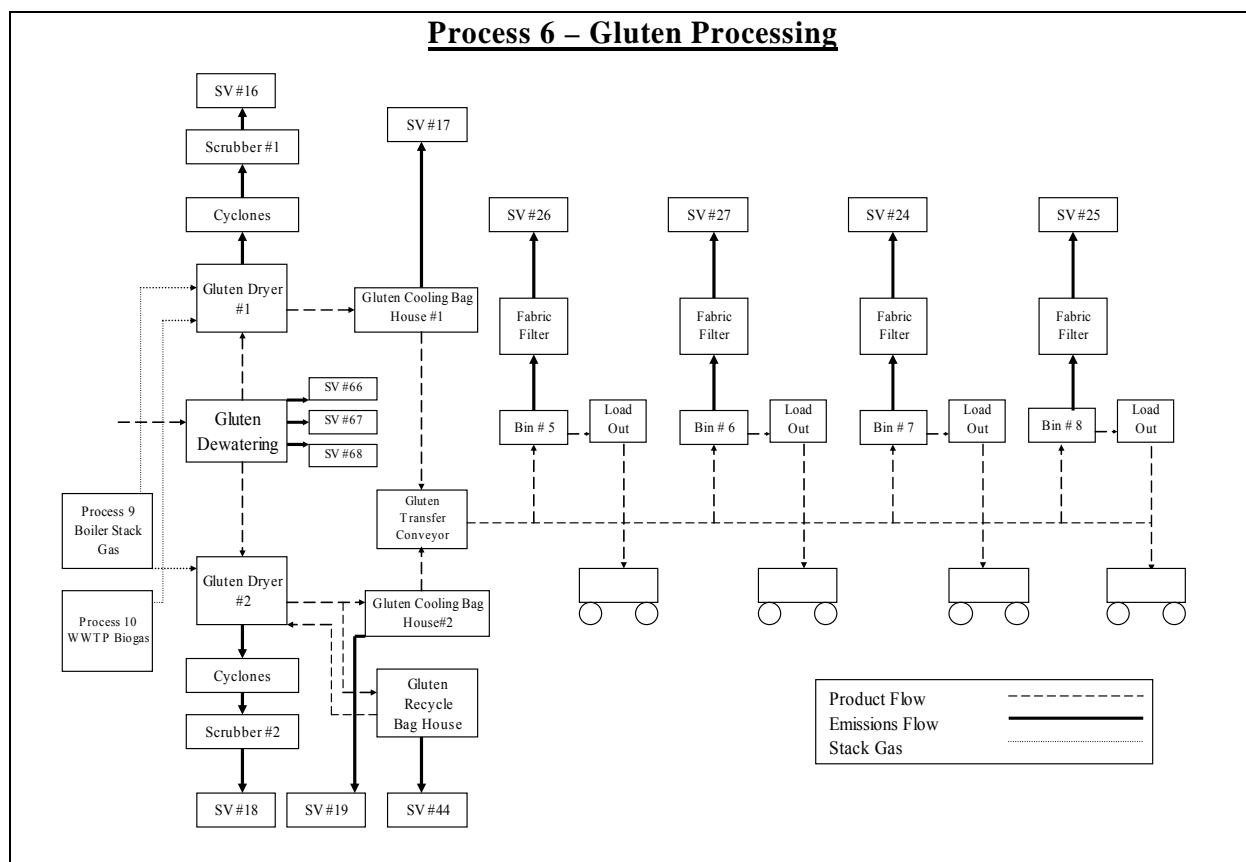
Recent sampling of the biogas stream indicates that the H<sub>2</sub>S concentration of this stream is higher than previously measured. For this reason, ADM is submitting a BACT analysis for the biogas vent stream.

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<sup>1</sup> The majority of this biogas is combusted in the Gluten Flash Dryer #1 with the balance combusted via an open flare when 100% of the gas cannot be fired in the dryer. During flaring events, emissions of SO<sub>2</sub> have been determined to be higher than previously estimated and/or measured. For this reason, ADM has determined that a BACT analysis and an associated BACT limit is needed to address these SO<sub>2</sub> emissions. No other emissions are affected by the H<sub>2</sub>S levels in this stream, therefore a BACT analysis is not needed for other pollutants.



**Figure 1-1. Wastewater Treatment Process Drawing**



## 4.0 SO<sub>2</sub> CONTROL TECHNOLOGY REVIEW

SO<sub>2</sub> emissions from the anaerobic digester system at Columbus result from oxidation of H<sub>2</sub>S present in the biogas. H<sub>2</sub>S is oxidized in either GFD #1 or the biogas flare. Under normal operating conditions, all of the biogas is routed to GFD #1 where SO<sub>2</sub> emissions from this dryer are controlled by a wet scrubber that uses caustic to neutralize the absorbed SO<sub>2</sub>. Under conditions where 100% of the biogas cannot be combusted in GFD #1, some of the biogas stream is routed to an open flare where the methane is oxidized to CO<sub>2</sub> and the H<sub>2</sub>S is oxidized to SO<sub>2</sub>.

Because the SO<sub>2</sub> emissions resulting from combustion of the biogas are vented from two separate processes and stacks, the BACT analysis must consider each of the processes independently. As an alternative, the BACT analysis can consider removal of H<sub>2</sub>S from the biogas prior to its combustion in either the flare or the dryer. ADM has evaluated the technical feasibility and the potential control efficiency of both of these alternatives

### 4.1 Control of SO<sub>2</sub> Emissions from Combustion Sources

As discussed, the current configuration of the biogas combustion system involves primary combustion of the biogas in GFD #1 and secondary combustion in the flare. Control options for each of these sources are reviewed below.

#### 4.1.1 Gluten Flash Dryer #1

ADM reviewed the RBLC to identify SO<sub>2</sub> control technologies that have been applied as BACT for similar dryers. The results of this review are summarized in Table 4-1. As this table shows, only two “technologies” are being

applied as BACT for this source category: wet scrubbing and the use of low-sulfur fuel. Although other technologies are theoretically feasible for application to this source (e.g., dry scrubbing), since GFD #1 is already equipped with a wet scrubbing system for SO<sub>2</sub> control, alternative technologies provide little or no potential improvement in SO<sub>2</sub> control at substantial added cost. Thus, the only technology that is practical to consider for application to this source (from an economic, energy, and environmental impact perspective) is the use of wet scrubbing with caustic addition.

**Table 4-1. Summary of RBLC Information for Gluten Dryers - SO<sub>2</sub>**

Company	RBLCID	Source	Technology	Limit(s)
ADM (formerly MCP)	NE-0014	Gluten Flash dryer #2	Cyclone/Wet Scrubber (w/ caustic addition)	0.081 lb/MMBtu 2.1 lb/hr
Cargill, Inc	NE-0016	Gluten Flash Dryer	No Controls Feasible	0.006 lb/MMBtu 0.027 lb/hr
Cargill, Inc	NE-0024	Gluten Flash Dryer	No Controls Feasible	0.156 lb/MMBtu* 7.0 lb/hr
ADM (formerly MCP)	MN-0026	Corn Gluten Dryer	Fuel spec: fuel limited to natural gas or biogas generated on-site.	0.081 lb/MMBtu* 3.15 lb/hr
ADM (formerly MCP)	MN-0039	Corn Gluten Dryer	Fuel spec: fuel limited to natural gas or biogas generated on-site.	0.385 lb/MMBtu* 15 lb/hr
Cargill	IA-0029	Gluten Flash Dryers (2)	Wet Scrubber w/ Caustic	0.13 lb/MMBtu* 3.25 lb/hr

\* Values calculated from heat input and lb/hr limits. Since the SO<sub>2</sub> is generated from the process and not from fuel sulfur combustion, this value is not meaningful for setting BACT limits but is presented here to provide a comparison that is size-independent.

Wet scrubbing with caustic addition is the top performing technology for gluten flash dryers and this technology is already installed on Gluten Flash Dryer #1 at the Columbus plant. Based on limited test data, ADM believes that this scrubber is achieving approximately 90% control of SO<sub>2</sub> emissions from the dryer. ADM evaluated options for increasing the SO<sub>2</sub> control efficiency in the existing scrubber above 90%. Since this scrubber already exists, its design is fixed. Possible options for boosting SO<sub>2</sub> removal efficiency are to: 1) increase the operating pH above the current range of 6.5 to 7.5 and/or; 2) increase the liquid recirculation rate above the current range of 500 to 600 gallons per minute.

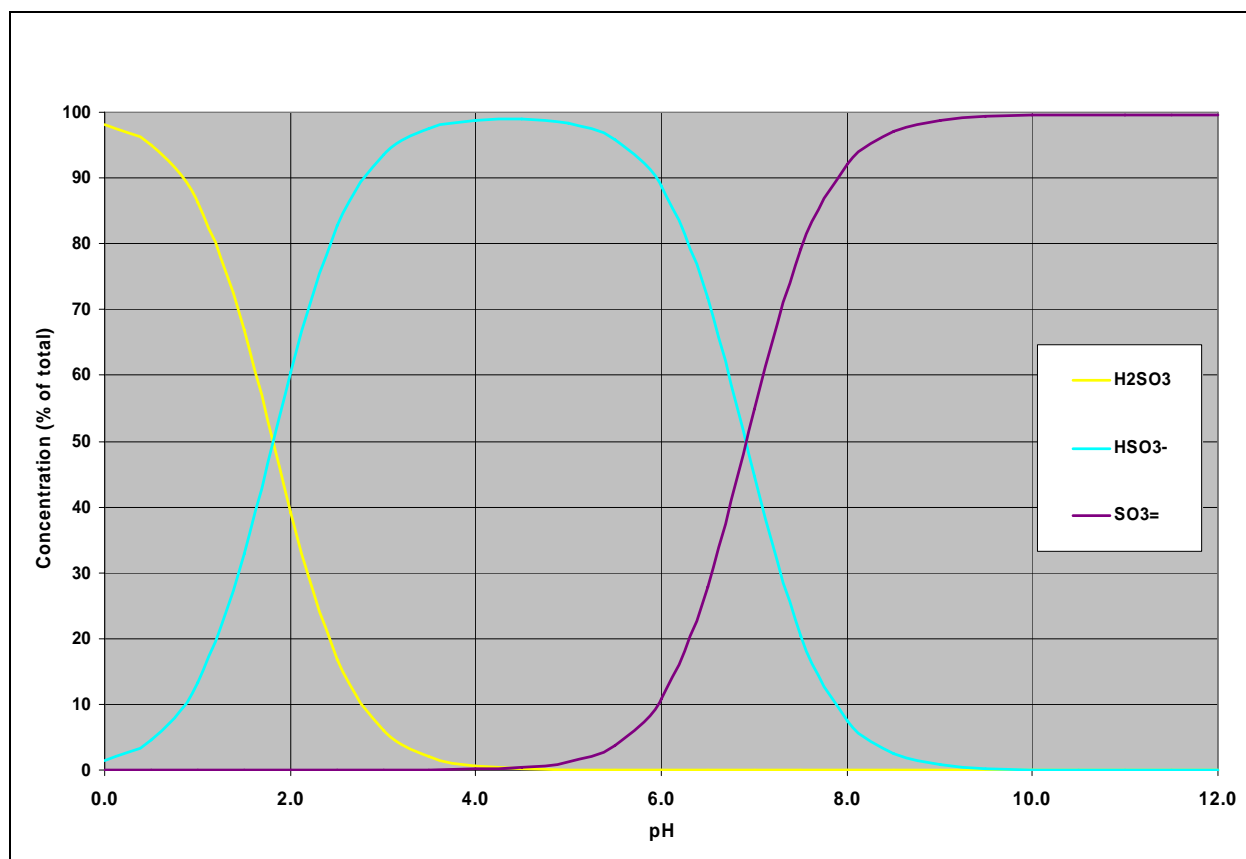
Operating at a higher pH (i.e., increased caustic addition) is not expected to boost SO<sub>2</sub> removal efficiency due to chemical equilibrium considerations. At pH 6.5, the acid-base equilibrium for absorbed SO<sub>2</sub> is such that virtually no SO<sub>2</sub> back-pressure exists.<sup>1</sup>

This effect is illustrated in Figure 4-1 which shows the equilibrium relationship between absorbed SO<sub>2</sub> (i.e., H<sub>2</sub>SO<sub>3</sub>) and the ionic sulfur species formed when SO<sub>2</sub> is absorbed into an aqueous solution (i.e., HSO<sub>3</sub><sup>-</sup> and SO<sub>3</sub><sup>=</sup>). As this figure shows, virtually no H<sub>2</sub>SO<sub>3</sub> exists at pH 6.5, thus indicating that no benefit in scrubber performance would be expected from operating at higher pHs. Further, operating at higher pH would significantly increase caustic consumption due to adsorption and neutralization of CO<sub>2</sub>.

<sup>1</sup> As used here, the term “back-pressure” refers to the vapor pressure of SO<sub>2</sub> over the scrubbing solution. When an aqueous alkaline solution is used to scrub SO<sub>2</sub>, a condition of zero back-pressure means that SO<sub>2</sub> removal is not affected by chemical equilibrium considerations. Under these conditions, SO<sub>2</sub> removal is instead limited by physical gas-liquid mass-transfer considerations (i.e., the gas-liquid contacting characteristics of the scrubber). Since elevating the scrubbing system pH has no affect on physical mass-transfer characteristics, SO<sub>2</sub> removal would not be affected by such a change.

The other alternative for boosting SO<sub>2</sub> removal performance is to increase the liquid recirculation rate through the scrubber. This option is not viable for the Columbus scrubber because the scrubber is already designed for the maximum feasible liquid rate. Further increases in liquid rate would result in scrubber flooding and the potential for reduced PM/PM<sub>10</sub> control efficiency due to mist carryover. Thus, increasing the liquid recirculation rate is not a feasible option for boosting SO<sub>2</sub> removal performance in the existing scrubber.

ADM also evaluated the option of adding a second scrubber in series with the existing scrubber. While this approach will result in increased SO<sub>2</sub> capture, it is quite expensive relative to the potential SO<sub>2</sub> emissions reductions achieved. ADM estimates that 99% SO<sub>2</sub> control efficiency could be achieved by adding a second scrubber downstream of the existing scrubber system (i.e., 90% control in the first scrubber and 90% control in the second scrubber for an overall control efficiency of 99%). However, the overall control efficiency of such a system is limited by the amount of biogas fired in the dryer and the amount that is flared. ADM estimates that a maximum of 25% of the biogas is flared. Assuming this is the case, the addition of a second scrubber results in 74% overall control as compared to a current baseline of 67.5% control.



**Figure 4-1. SO<sub>2</sub> Aqueous Equilibrium Species Concentrations vs. pH**

## 4.2 Control of SO<sub>2</sub> Emissions from Flaring Operations

Currently, biogas that is not combusted as fuel in Gluten Flash Dryer #1 is combusted in an open-flame flare where the methane is converted to CO<sub>2</sub> and the H<sub>2</sub>S is converted to SO<sub>2</sub>. Based on ADM's review of the RBLC, SO<sub>2</sub> emissions from such flares are not typically controlled. The results of ADM's RBLC search are summarized in Table 4-2.



**Table 4-2. Summary of RBLC Data for WWTP Biogas Flares**

<b>Company</b>	<b>RBLC ID</b>	<b>Source</b>	<b>Technology</b>
Anheuser-Busch, Inc.	TX-0382	Biogas	No Controls Feasible
Biorecycling Technologies, Inc	CA-0824	Biogas	No limit on SO <sub>2</sub> or H <sub>2</sub> S emissions.
City of Stockton, CA	CA-0752	Digester gas	LPG or Natural Gas pilot flame.
Grain Processing Corp.	IN-0075	Biogas	No limit on SO <sub>2</sub> or H <sub>2</sub> S emissions.
IBP, Inc.	NE-0020	Biogas	Pollution Prevention - Limit TRS to Flare
United Wisconsin Grain Producers	WI-0204	Biogas	No limit on SO <sub>2</sub> or H <sub>2</sub> S emissions.

Although SO<sub>2</sub> controls are not typically applied to an open flame flare, it is possible to control SO<sub>2</sub> emissions from an enclosed flare. Thus one control option for the flared biogas would be to replace the open flare with an enclosed flare and then to treat the flare exhaust gas in an SO<sub>2</sub> (caustic) wet scrubber. ADM has evaluated this option and determined that 90% control of the SO<sub>2</sub> emissions from the flare could be achieved using this approach. Assuming that a maximum of 25% of the biogas is flared, this results in an overall reduction in SO<sub>2</sub> emissions of 22.5%.<sup>1</sup>

### ***4.3 Control of SO<sub>2</sub> Emissions by Biogas Treatment***

A third option for controlling SO<sub>2</sub> emissions from biogas combustion is pretreatment of the biogas to remove H<sub>2</sub>S. This approach has the effect of controlling SO<sub>2</sub> emissions from both the flare and the gluten flash dryer. A number of options are available for H<sub>2</sub>S control and each one is capable of fairly high H<sub>2</sub>S (SO<sub>2</sub>) control efficiencies. For purposes of this BACT analysis, ADM estimates that a biogas H<sub>2</sub>S control system is capable of 95% reduction in SO<sub>2</sub> emissions. Additionally, the existing gluten flash dryer SO<sub>2</sub> scrubber would provide 90% control of the SO<sub>2</sub> in the biogas fired in the dryer. Assuming that 25% of the biogas is flared, this control option would result in an overall SO<sub>2</sub> control efficiency of 98.4%.<sup>2</sup>

The various options available for removing H<sub>2</sub>S from biogas are discussed briefly below.

#### **4.3.1 Dry H<sub>2</sub>S Removal Processes**

Dry removal process can be divided in processes that absorb and react with H<sub>2</sub>S to form solid sulfur compounds, and adsorbents which rely on physical capture of a gas-phase particle onto a solid surface with subsequent regeneration of the sorbent. The typical dry sorption process is configured with the dry media in vessels where gas flows upwards or downwards through the media. Because the dry-sorption media eventually becomes saturated with contaminant and inactive, it is common to have two vessels operated in parallel so one vessel can remain in service while the other is offline for media replacement or regeneration.

<sup>1</sup> Note that the SO<sub>2</sub> emissions reductions projected for this option may be optimistic and not achievable due to the potential for sulfur species collected by the scrubbers to be recycled back to the biogas stream. In other words, SO<sub>2</sub> collected in the scrubber returns to the WWTP where some fraction of the sulfur is converted into H<sub>2</sub>S. This recycle loop has the effect of raising the SO<sub>2</sub> concentration in the combustion products from the dryer and/or flare and thereby increasing SO<sub>2</sub> emissions from this source at least partially negating the benefit of increased scrubbing. The degree of this “recycle concentration effect” is unknown, but it will tend to reduce the projected SO<sub>2</sub> control efficiency from control options that rely on increased SO<sub>2</sub> scrubbing.

<sup>2</sup> Overall Efficiency = 95% biogas H<sub>2</sub>S control plus 90% control of 75% of the uncontrolled H<sub>2</sub>S in GFD #1 scrubber =  $0.95 + (1-0.95) \times (0.9) \times (1-0.25) = 98.4\%$

## Dry Absorbent Processes

Iron oxides, zinc oxides, and alkaline solids are common absorbents used to react with and chemically bind sulfur compounds. While the benefits of using dry absorption processes include simple and effective operation, there are critical drawbacks to these technologies. The process is highly chemical intensive, and a continuous stream of spent waste material is accumulated. Both the chemical costs and waste disposal volume/cost increase with increasing sulfur loads. Generally, dry absorption processes are not economical for sulfur loadings greater than 500 lb/day. Above this level of sulfur loading, other processes are more cost-effective.

## Dry Adsorbent Processes

Adsorbents rely on physical adsorption of a gas-phase particle onto a solid surface, rather than chemical transformation as discussed with the previous dry absorbents. High porosity and large surface areas are desirable characteristics, enabling more physical area for adsorption to occur. Typical adsorbent materials include Zeolites (molecular sieves), activated carbon, and activated carbon impregnated with alkaline or oxide solids to enhance the physical adsorptive characteristics of the carbon. The adsorbent eventually becomes saturated and must be regenerated, and at some frequency replaced. During regeneration, an H<sub>2</sub>S-rich gas is released and must be vented or reused appropriately or subjected to another process for sulfur recovery. The primary dry adsorbent/regeneration processes use temperature swing, pressure swing, or inert purge to regenerate the sorbent.

Temperature swing adsorption/regeneration uses the differences between the equilibrium loadings of H<sub>2</sub>S at two temperatures. Considerable energy and time are required to heat and cool the bed. Pressure swing adsorption/regeneration uses the difference between equilibrium loadings at two pressures. Typically adsorption takes place at elevated pressures to allow for regeneration at atmospheric pressure or under slight vacuum. The inert purge regeneration process passes a non-adsorbing gas through the sorbent bed, reducing the partial pressure of H<sub>2</sub>S in the gas-phase so that desorption occurs. Displacement purge regeneration uses a purge gas that is more strongly adsorbed than the H<sub>2</sub>S displacing the adsorbed H<sub>2</sub>S from the sorbent.

### **4.3.2 Liquid H<sub>2</sub>S Removal Processes**

The liquid phase H<sub>2</sub>S removal process can be divided into three types: processes that use liquid-redox reactions to absorb the H<sub>2</sub>S and convert it to sulfur, alkaline solution processes that absorb the H<sub>2</sub>S produce a liquid waste stream, and regenerable absorbents.

## Liquid Redox Processes

Liquid redox processes react H<sub>2</sub>S with metallic solutions, such as iron oxide/chelates, zinc oxide/acetates, vanadium salts with quinines, etc. Regeneration is achieved by aeration, converting the metal sulfide to elemental sulfur. The most commonly used liquid redox processes include LO-CAT® and SulFerox® processes (which currently dominate the chelated-iron H<sub>2</sub>S removal market), Chemsweet® a zinc-oxide liquid-based process, and the Stretford process which uses quinones with vanadium salts. These processes are typically used for the removal of greater than 500 lb/day of H<sub>2</sub>S.

## Alkaline Solution Processes

The alkaline solution processes react acid gases such as H<sub>2</sub>S and CO<sub>2</sub> to remove them from the gas stream to be cleaned. Regenerative processes employ alkaline salts including sodium and potassium carbonate, phosphate, borate, arsenite, and phenolate, as well as salts of weak organic acids. The Thiopaq Process absorbs SO<sub>2</sub> and H<sub>2</sub>S in a traditional chemical scrubber with sodium bicarbonate solution. The spent liquid is then regenerated in a separate bioreactor, producing elemental sulfur.

Since CO<sub>2</sub> is also absorbed and neutralized by aqueous alkaline solutions, chemical consumption for throw-away processes will be high for gas streams containing significant amounts of CO<sub>2</sub>, such as anaerobic digester gas.

Hydroxide solutions (e.g., sodium hydroxide) are very effective at removing CO<sub>2</sub> and H<sub>2</sub>S, but are non-regenerable. Non regenerable processes generate a high volume wastewater stream and are not well suited for applications treating more than 500 lb/day H<sub>2</sub>S.

### Amine Solution Processes

Amine processes constitute the largest portion of liquid-based natural-gas and petroleum refinery gas purification technologies for removal of acid gases. They are attractive because they can be configured with high removal efficiencies, designed to be selective for H<sub>2</sub>S or both CO<sub>2</sub> and H<sub>2</sub>S, and are regenerable. Drawbacks of using an amine system, as with most liquid-based systems, are more complicated flow schemes, foaming problems, chemical losses, higher energy demands, and how to dispose of foul regeneration air. Alkanolamines generally contain a hydroxyl group on one end and an amino group on the other. The hydroxyl group lowers the vapor pressure and increases water solubility, while the amine group provides the alkalinity required for absorption of acid gases. These processes generate an H<sub>2</sub>S rich gas stream that must be used or converted to a sulfur product (elemental sulfur, gaseous SO<sub>2</sub>, H<sub>2</sub>SO<sub>4</sub>). Oxygen (O<sub>2</sub>) present in biogas can degrade the amine. Thus, an O<sub>2</sub> scavenger system might be needed upstream of the amine scrubber to minimize amine degradation. These systems are typically used in applications processing very large quantities of sulfur (i.e., more than 60,000 lb/day).

### Physical Solvent Processes

When acid gases make up a large proportion of the total gas stream, the cost of removing them with heat-regenerable processes, such as amines, may be out of line with the value of the treated gas. Physical solvents, where the acid gases are simply dissolved in a liquid and flashed off elsewhere by reducing the pressure, have been employed with limited success. Liquids with solubilities for CO<sub>2</sub> and H<sub>2</sub>S much greater than water are typically chosen over water, but the principal advantages of water as an absorbent are its availability and low cost. Absorption of acid gas produces mildly corrosive solutions that can be damaging to equipment if not controlled.

Solvents such as methanol, propylene carbonate, and ethers of polyethylene glycol, among others, are offered as physical solvents. Criteria for solvent selection include high absorption capacity, low reactivity with equipment and gas constituents, and low viscosity. Thermal regeneration techniques are needed to achieve pipeline-quality gas. An example of physical solvent based process is the Selexol process utilizing dimethylether of polyethylene glycol.

## **4.3.3 Membrane Processes**

Membranes operate based on differing rates of permeation through a thin membrane, as dictated by partial pressure. Because of this, 100% removal efficiency is not possible in one stage, and a significant fraction of the H<sub>2</sub>S will not be removed. Two types of membrane systems exist: high pressure with gas phase on both sides, and low pressure with a liquid adsorbent on one side. Membranes are generally not used for the gross removal of H<sub>2</sub>S from biogas, but are becoming more attractive as a polishing unit for upgrading of biogas to natural-gas standards because of attributes such as reduced capital investment, ease of operation, low environmental impact, gas dehydration capability, and high reliability.

## **4.3.4 Biological H<sub>2</sub>S Removal Methods**

Biologically active agents have been used in a variety of process arrangements, such as bio-filters, fixed-film bio-scrubbers, and suspended-growth bio-scrubbers. Desirable attributes for bio-filters include high surface area, low pressure-drop, good moisture retention, and durable filter support media. The trade-off between organic and inorganic media is traditionally that organic composites have vibrant microbial populations and form extremely active bio-layers, but they degrade quickly at low pH and have higher pressure-drops than inorganic carriers. There are many companies specializing in the design and operation of bio-filters for pollution control.

### 4.3.5 Selection of H<sub>2</sub>S Removal Method

The H<sub>2</sub>S control processes described above all provide similar H<sub>2</sub>S control efficiency performance levels (i.e., 95% control). Therefore the choice of technology is based on practical applicability, cost, and environmental factors.

From a practical applicability perspective, there are three size ranges of sulfur recovery applications. The small-size applications remove less than 500 lb/day of H<sub>2</sub>S from the gas stream. Typically these applications utilize non-regenerable dry processes unless waste storage/disposal is very costly. The medium-size applications remove less than 60,000 lb/day of H<sub>2</sub>S from the gas stream. Typically these applications utilize regenerable processes that produce sulfur products (i.e., sulfur, SO<sub>2</sub>, H<sub>2</sub>S, and H<sub>2</sub>SO<sub>4</sub>) or non-regenerable processes with sulfur containing waste streams (e.g., diluted sodium sulfate). The large-size applications remove greater than 60,000 lb/day of H<sub>2</sub>S from the gas stream. Typically these applications utilize regenerable amine processes which produce H<sub>2</sub>S. The H<sub>2</sub>S is then processed into either elemental sulfur using a Claus sulfur recovery plant, or sulfuric acid (H<sub>2</sub>SO<sub>4</sub>) using a contact process sulfuric acid plant. In most instances, economics, not technical feasibility, determines which process is used.

The anaerobic digester at the Columbus plant can generate a maximum of about 1,000 lb/day of H<sub>2</sub>S making the biogas treatment system a small to medium-size application. ADM has investigated the capital and annual costs of several processes including: caustic scrubbing (a non-regenerable liquid absorption process), water scrubbing (a physical solvent process) followed by a bio-scrubber (a biological process), Lo-Cat (a liquid-redox process), and Crystasulf (a liquid-redox process). Caustic scrubbing is the lowest capital cost system but has the largest annual costs due to caustic consumption to remove the H<sub>2</sub>S along with much of the CO<sub>2</sub> because caustic scrubbing is not selective but removes any acid gas. Crystasulf is the highest capital cost system but has the lowest annual cost. The annualized costs (including capital recovery) of all four processes are about the same.

In the end, ADM has determined that the LO-CAT® process is best suited for this application. LO-CAT® will achieve at least 95% control of the H<sub>2</sub>S in the biogas stream, it has flexible operation, allowing 100% turndown in gas flow, it produces elemental sulfur which is the most useful, concentrated byproduct possible, it does not use any toxic chemicals, and it does not produce any hazardous waste byproducts.

### 4.4 Control Technology Hierarchy and Impacts Analysis

Table 4-3 lists the control technology hierarchy for the control options evaluated for the Columbus plant's biogas stream along with the estimated economic and environmental impacts of each option. As this table shows, four options are considered with overall control efficiencies ranging from the current 67.5% up to 98.4%. Table 4-3 also shows the annualized costs and emissions reductions projected for each of the control options. As this table shows, the best performing technology option is the addition of a LO-CAT® system for control of H<sub>2</sub>S in the biogas prior to combustion in either the flare or GFD #1. However, the control cost-effectiveness of this option is in excess of \$11,600 per ton of SO<sub>2</sub> controlled. This cost represents an unacceptably high economic impact.

Table 4-3 also shows that the other control schemes involving addition additional control equipment (beyond that already installed on the gluten flash dryer) are even more expensive than the top-performing option. Based on this assessment, ADM concludes that BACT for the anaerobic digester biogas vent is the existing GFD #1 SO<sub>2</sub> scrubber. This conclusion is contingent only on the assumption that no more than 25% of the biogas is routed to the flare (i.e., at least 75% of the biogas is combusted in the dryer). In reviewing past data on biogas flaring, ADM believes that this assumption is conservative (i.e., much less than 25% of the biogas is flared). Further, since combustion of biogas in the gluten dryer displaces the use of expensive natural gas, ADM has an economic incentive to minimize flaring of this fuel.

**Table 4-3. Biogas Control Technology Ranking and Analysis**

<b>Technology</b>	<b>Overall Control Efficiency</b>	<b>SO<sub>2</sub> Emissions Reduction (tpy)</b>	<b>Annualized Costs (Capital + O&amp;M)</b>	<b>Control Cost-Effectiveness (\$/ton)</b>	<b>Energy Impacts (MWh/yr)</b>	<b>Environmental Impacts</b>
LO-CAT® + Existing GFD SO <sub>2</sub> Scrubber	98.4%	40.4	\$471,127	\$11,658	969	Reduced load on WWTP; some combustion emissions from small burner
Enclosed Flare + Flare SO <sub>2</sub> Scrubber + Existing GFD SO <sub>2</sub> Scrubber + New GFD SO <sub>2</sub> Scrubber	96.8%	38.3	\$1,078,015	\$28,158	1,747	Additional load on WWTP
Enclosed Flare + Flare SO <sub>2</sub> Scrubber + Existing GFD SO <sub>2</sub> Scrubber	90.0%	29.4	\$471,499	\$16,010	65	Additional load on WWTP
Existing GFD SO <sub>2</sub> Scrubber + New GFD SO <sub>2</sub> Scrubber	74.3%	8.8	\$606,516	\$68,649	1,682	Additional load on WWTP
Existing GFD SO <sub>2</sub> Scrubber	67.5%	Baseline	\$0	Baseline	Baseline	Baseline

#### ***4.5 Proposed BACT for Digester Biogas Vent***

Based on the analysis provided in the preceding subsections, ADM concludes that BACT for the Columbus digester biogas vent is the use of the existing wet scrubbing system on the gluten flash dryer. The proposed short-term BACT limit for this stream is based on combustion of a maximum of 350 scfm of biogas at an H<sub>2</sub>S concentration of 1.2%. The SO<sub>2</sub> produced from this biogas combustion in GFD #1 will be controlled at 90% efficiency, which equates to an hourly SO<sub>2</sub> emissions rate of 4.2 lb/hr. In addition, SO<sub>2</sub> emissions from the drying process amount to an estimated 2.4 lb/hr.<sup>1</sup>

Therefore, the proposed BACT SO<sub>2</sub> emissions limit for GFD #1 is 6.6 lb/hr (i.e., 4.2 lb/hr from biogas combustion plus 2.4 lb/hr from process SO<sub>2</sub>). Note that this short term limit is based on a short-term biogas production rate that exceeds the estimated annual average biogas rate of 250 scfm at 1.2% H<sub>2</sub>S (equivalent to 3.0 lb/hr of SO<sub>2</sub> on an annual average basis). ADM has completed an air quality impact modeling analysis (submitted in conjunction with

<sup>1</sup> This value is the estimated BACT limit for GFD #1 in absence of biogas firing (i.e., it is identical to the proposed BACT limit for GFD #2 subsequent to its modification to have a capacity similar to GFD #1 – See August 2004 permit application addendum).

this BACT analysis) using the proposed short term BACT limit to demonstrate that no NAAQS or increment issues exist due to combustion of the biogas in either the dryer or the flare.

## **Appendix F - HAP-BACT Analysis for Existing Sources**

## **1. HAP Best Available Control Technology (BACT) Review**

Title 129, Chapter 27 of the Nebraska Administrative Code (N.A.C.) requires application of BACT for construction, reconstruction, or modification of a source with the potential to emit any hazardous air pollutant (HAP) in an amount equal to or in excess of two and one-half (2.5) tons/year or more of any individual hazardous air pollutant or an aggregate of ten (10.0) tons/year or more of any combination of hazardous air pollutants. In a meeting with ADM representatives on September 25, 2003, NDEQ clarified that this HAP BACT requirement applies to all new, reconstructed, or modified sources of HAP emissions at a facility if that facility's HAP emissions exceed the 2.5/10.0 tpy applicability thresholds. If the facility's emissions exceed these thresholds, there is no de minimis threshold for applicability to individual sources. Because this regulation was in effect prior to the construction of the Columbus plant, and since HAP emissions from the Columbus plant exceed the applicability thresholds, ADM is required to identify and apply BACT to all sources of HAP within the facility.<sup>1</sup>

The existing sources within the Columbus Corn plant that may emit HAP are listed in Table 1-1. The remainder of this appendix provides a HAP BACT analysis for each of these sources. Sources with similar emissions characteristics and control options are grouped together in the following discussion.

ADM has used a "top-down" approach to evaluate BACT for each of these sources. The top-down BACT approach identifies and ranks feasible control technologies based on their effectiveness in reducing emissions. If the most effective technology is accepted as BACT, the analysis stops. However the most effective technology is often evaluated to determine economic, energy, and environmental impacts. If these impacts are unacceptable, the top technology is rejected as BACT and the next best performing technology is evaluated. This process continues until an acceptable BACT technology is identified.

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<sup>1</sup> For purposes of this analysis, ADM has used the listing of HAP found at N.A.C. Title 129, Appendix II.



**Table 1-1. Listing of Corn Plant Potential Sources of HAP Emissions**

<b>Source Description</b>	<b>Emission Unit ID</b>
Boiler #1	EU9-38
Boiler #2	EU9-39
Boiler #3 & 4	EU9-40 and EU9-41
Liquid Product Loadout	EU7-90
Storage Tanks	EU7-TK01 through EU7-TK08
Equipment Leaks	EQ LKS FUG
Millhouse Ventilation System	EU3-5
Germ Dryers 1-3	EU5-7A through EU5-7C
Fluid Bed Germ Dryer	EU5-8
Gluten Flash Dryer #1	EU6-16
Gluten Flash Dryer #2	EU6-18
Germ Coolers #1-4	EU5-9A, EU5-9B, EU5-9C, EU5-12
Gluten Coolers, Gluten Recycle	EU6-17, EU6-19, EU6-44
Fermenters/CO <sub>2</sub> Scrubber East	EU7-32
Fermenters/CO <sub>2</sub> Scrubber West	EU7-33
Distillation & Dehydration Vent	EU7-34
Carbon Furnace #1	EU8-35
Carbon Furnace #2	EU8-36
Anaerobic Digester Biogas flare	EU10-41
Fiber Dewatering	EU11-43
Gluten RVF SE <sup>1</sup>	EU6-66
Gluten RVF SW <sup>1</sup>	EU6-67
Gluten RVF NW <sup>1</sup>	EU6-68
Stillage/Steepwater Evaporator (E) <sup>1</sup>	EU12-69
Stillage/Steepwater Evaporator (W) <sup>1</sup>	EU12-70
Diesel Generator & Fire Pumps	EU-95, EU-96, EU-97, EU-99, EU-107, EU-108
HCl Receiving and Storage	EU8-91

## 1.1 Gas-fired Boilers

There are four gas-fired boilers at the Columbus plant. Currently, these boilers provide the steam needed to support the various processes and operations at the plant. Testing (e.g., AP-42) has shown that trace amounts of HAP are emitted from industrial gas boilers similar to those at the Columbus plant.

The issue of controlling HAP emissions from industrial boilers has most recently been thoroughly investigated by U.S. EPA in support of the rule-making effort for the Industrial Boiler MACT Standard (i.e., 40 CFR 63 Subpart DDDDD). In the preamble to the proposed regulation, EPA states:

***“We found that no existing units in the gaseous fuel-fired subcategories were using control technologies that achieve consistently lower emission rates than uncontrolled sources for any of the pollutant groups of interest. Therefore, we are unable to identify***

<sup>1</sup> Following completion of the projects described in this application, these sources will all vent through a common control system and stack (SV-5).

*the best performing 12 percent of units in the subcategories. Consequently, EPA determined that no existing source MACT floor based on control technologies could be identified for gaseous fuel-fired units. Therefore, we concluded the MACT floor for existing sources in this subcategory is no emissions reductions for nonmercury metallic HAP, mercury, inorganic HAP, and organic HAP.”<sup>1</sup> [emphasis added]*

EPA also looked at technologies that went beyond the MACT floor and concluded:

*“Given the cost and the uncertain emissions reductions that might be achieved, we chose to not require CO monitoring and emission limits as MACT.”<sup>2</sup>*

Thus, in the proposed MACT regulation for industrial boilers, the only requirement applicable to existing gas-fired industrial boilers is that they be operated and maintained according to the provisions of 40 CFR 63.6(e)(1)(i) which states<sup>3</sup>:

“At all times, including periods of startup, shutdown, and malfunction, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. During a period of startup, shutdown, or malfunction, this general duty to minimize emissions requires that the owner or operator reduce emissions from the affected source to the greatest extent which is consistent with safety and good air pollution control practices. The general duty to minimize emissions during a period of startup, shutdown, or malfunction does not require the owner or operator to achieve emission levels that would be required by the applicable standard at other times if this is not consistent with safety and good air pollution control practices, nor does it require the owner or operator to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved.”

ADM believes that EPA’s conclusions regarding MACT are also appropriate for determining HAP BACT for the four gas boilers at the Columbus plant. The current HAP emissions from these units are quite low and the emissions reductions that might be achieved (if any) are uncertain. Further, the expectation is that once the CFB boilers become operational, the actual emissions from the gas boilers will be reduced as boiler utilization is reduced. For these reasons, ADM concludes that HAP BACT for the four gas-fired boilers at the Columbus plant is to comply with the requirements of 40 CFR 63.6(e)(i) as described above. This is the top performing HAP control technology as identified by EPA in the MACT standard setting process.

## **1.2 Ethanol Loadout**

When alcohol from the Columbus plant is loaded into trucks and rail cars for shipment offsite, VOC is emitted as vapor in the transport vehicles is displaced by the liquid being loaded. Most of the VOC in this displaced vapor is ethanol, which is not a HAP. However, depending on the composition of the vapors that are displaced from the transport vehicles, some HAP may also be emitted.

ADM recently installed and is operating a thermal oxidizer (more specifically an open flare) to control emissions of VOC from the loadout operations at the Columbus plant. This flare will also serve to control emissions of organic HAP, which are the only expected type of HAP emissions from the loading

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<sup>1</sup> 68 FR 1677.

<sup>2</sup> *Ibid.*

<sup>3</sup> 68 FR 1704 (§63.7505(b))

operation. The question that must be addressed is whether this flare constitutes HAP BACT for the loadout operations.

A review of available information on the control of organic VOC emissions indicates that thermal oxidation is the single most commonly used technology to meet BACT requirements for sources that cannot be controlled through source reduction or pollution prevention measures. In addition, thermal oxidation is the basis for determining MACT for certain sources of HAP emissions (e.g., 40 CFR 63, Subpart DDDD - National Emission Standards for Plywood and Composite Wood Products Manufacture). For these reasons, ADM concludes thermal oxidation of the loadout vapors is the top performing technology for control of both VOC and HAP emissions. Since a flare has already been installed to collect and oxidize emissions from the Columbus plant's loadout operations, ADM concludes that BACT for HAP is meeting the 95% VOC control requirement for the existing flare and a 100% capture efficiency.

### **1.3 Wastewater Treatment Plant (WWTP) Flare**

The anaerobic digesters in the Columbus plant's WWTP emit a gas stream that has a high heating value. This stream contains various organic compounds, some of which may be VOC and/or HAP. Currently, this stream is either combusted in a flare or it is combusted in the No. 1 Gluten Flash Dryer. The flare, as well as the dryer, act as thermal oxidation devices to effectively control emissions of VOC and organic HAP from the WWTP. As discussed in Section G.2 above, thermal oxidation is the most effective means of controlling organic HAP emissions. Thus, ADM concludes that the current control system for the WWTP off-gas stream represents BACT for controlling HAP emissions from this source.

### **1.4 Alcohol and Denaturant Storage Tanks**

Tanks are used to store various products and intermediates at the Columbus plant. In these tanks, vapors are emitted due to both working and breathing losses. Vapor losses from tanks that store ethanol may contain small quantities of HAP as do the vapors emitted from tanks that store denatured alcohol and denaturant (gasoline). These tanks are listed in Table 1-2.

**Table 1-2. Alcohol and Denaturant Tanks at the Columbus Plant**

<b>EP #</b>	<b>Tank #</b>	<b>Description</b>	<b>Size (gal)</b>	<b>Type</b>
45	1080-1	Ethanol Day Tank	100,000	IFR
46	1080-2	Ethanol Day Tank	100,000	IFR
47	1080-3	Ethanol Rerun Tank	34,000	IFR
48	1080-4	Ethanol Day Tank	100,000	IFR
49	1080-5	Denaturant Tank	42,000	IFR
50	1080-6	Ethanol Storage Tank	2,284,000	IFR

Currently each of the alcohol and denaturant storage tanks is equipped with an internal floating roof (IFR).

Based on a review of the RBLC, the applicable NSPS, and other sources of technical information (e.g., AP-42), the options for controlling organic vapor loss emissions from tanks include the following:

- Fixed roof tanks equipped with conservation (pressure/vacuum) vents;
- Floating roof tanks (internal or external);

- Fixed roof tanks equipped with vapor collection and control equipment.

For tanks already equipped with an internal floating roof such as the alcohol and denaturant tanks at Columbus, VOC emissions are quite low and HAP emissions are even lower.<sup>1</sup> While it is theoretically possible to install a vapor collection and control system to further reduce emissions from such tanks, the control cost effectiveness would be approximately \$2 million per ton of HAP controlled.<sup>2</sup> For this reason, ADM concludes that the existing internal floating roof tanks installed on the alcohol and denaturant storage tanks at the Columbus plant represent BACT for both VOC and HAP emissions. These tanks are subject to 40 CFR 60, Subpart Kb, and ADM concludes that compliance with the requirements of Subpart Kb is sufficient to meet the HAP BACT requirement for these sources.

In addition to the floating roof tanks, there is a fixed-roof tank used for storage of corrosion inhibitor at the Columbus plant (Tank 1080-07; SV-51). This tank (which is equipped with a conservation vent) has estimated potential HAP emissions of less than  $3.0 \times 10^{-3}$  tons per year. Based on this low emissions rate, ADM concludes that there are no cost-effective control options that could be applied to this tank. For example, an annual cost of control of as little as \$30 would equate to a control cost-effectiveness of \$10,000 per ton. No available control options have an annualized cost of anywhere near \$30 per year. For this reason, ADM concludes that HAP BACT for this tank is no added control.

## 1.5 Fugitive Emissions

ADM has identified the following potential sources of fugitive HAP emissions from the Columbus plant:

- Process and piping fugitives in the alcohol plant; and
- The wet feed handling and storage operations.

Each of these sources is discussed in more detail in the following subsections.

### 1.5.1. Process and Piping

Emissions from leaking valves, flanges, pumps, and other process and piping sources have long been recognized as fugitive emissions sources in various industries. The process and piping fugitive sources in ADM's alcohol production plant are primarily sources of ethanol emissions, and not HAP. However, based on other testing done by ADM, it is reasonable to conclude that some small fraction of these fugitive emissions is HAP (e.g., acetaldehyde).

Based on a review of the RBLC and other technical sources of information, the only technically feasible control option for these potential sources of HAP emissions is a leak detection and repair (LDAR) program. At the Columbus plant, process and piping fugitive sources are subject to the requirements of 40 CFR 60, Subpart VV which requires that ADM implement an LDAR program for fugitive VOC emissions in its alcohol plant. The requirements of Subpart VV help ensure that fugitive VOC emissions

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<sup>1</sup> The estimated potential VOC emissions from the CDA and denaturant storage tanks at Columbus are less than 3 tons per year and the estimated HAP emissions rate is less than 0.05 tons per year (see Tanks 4.0 report in Attachment G-1).

<sup>2</sup> Based on the cost of installing a vapor collection system and a flare (minimum installed cost of \$55,000 and annualized costs of \$91,157 – see attached COST-AIR spreadsheet) and a maximum estimated HAP emissions rate of less than 0.05 tons per year.

are minimized. Since compliance with Subpart VV will also minimize HAP emissions from the alcohol plant fugitive VOC sources, ADM concludes that the requirements of Subpart VV represent HAP BACT for these emissions sources.

### **1.5.2 Wet Feed Handling and Storage**

One of the products from the Columbus corn mill is animal feed. Unlike some corn mills, the Columbus plant produces a feed product that is about 60 wt.% water. This wet feed is temporarily stored on an open concrete pad before it is loaded into trucks for transport to the end user. Tests have shown that the water in the wet feed contains a small amount of both VOC (primarily ethanol) and HAP (primarily acetaldehyde). As the wet feed is loaded onto or off of the pile and as the feed sits on the pile, some of the moisture and VOC evaporates. ADM has conducted laboratory tests and used these as the basis for estimating both VOC and HAP emissions from the wet feed storage and handling operations at the Columbus plant. Based on this analysis, ADM estimates that HAP emissions from the wet feed pile are less than 4 tons per year.

By definition, HAP emissions from the wet feed operations are fugitive. That is, they are “emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.” The key word in this definition is “reasonable” meaning that although it might be theoretically possible to enclose the emission and collect them, it is not reasonable to do so. Given the size of the wet feed operations at Columbus (i.e., the feed storage and loadout operations cover approximately ½-acre) and the limited HAP emissions estimated to occur from these operations, it is not reasonable to enclose or otherwise contain and capture these emissions. For this reason, ADM concludes that HAP BACT from the wet feed storage and handling operations is no control (i.e., there are no technically and economically feasible control options for this source of emissions).

### **1.6 Millhouse Ventilation System**

As a result of recent testing, ADM has determined that there are small quantities of HAP in some of the Columbus corn mill exhaust streams. Additionally, there are VOC present that must be controlled pursuant to the National Consent Decree. As part of the activities covered by this permit application, ADM plans to upgrade and/or optimize the millhouse ventilation scrubber system to meet the 95% VOC control requirement of the CD. Additionally, ADM will re-route the exhaust from the stillage MR vents to this scrubber to meet CD mandated VOC control requirements. Finally, ADM plans to route the gluten RVF vents to the millhouse scrubber system.

The current estimate of VOC emissions from this combined stream prior to the planned millhouse ventilation scrubber system improvements is 163 tons per year. Of this VOC, ADM estimates that a maximum of 10 wt.% is HAP.<sup>1</sup> Thus, prior to the control system improvements, the maximum HAP emissions from the combined stream are 16.3 tons per year.

After reviewing the RBLC and other sources of information regarding potential organic HAP control technologies, ADM concluded that the two technically feasible HAP control options are the upgrade of the millhouse scrubber ventilation control system to 95% VOC control and the addition of a thermal oxidation system downstream of the existing millhouse scrubber system to reduce VOC emissions by an additional 95% (i.e., 95% control of the VOC emissions from the existing millhouse scrubbing system). The most effective (from an emissions control standpoint) of these options is to install an add-on thermal

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<sup>1</sup> HAP fractions in the subject streams at the Columbus plant range from 2 to 9 wt.% of the VOC present. A conservative value of 10% has been used in this analysis.

oxidizer to treat the combined stream. ADM has used U.S. EPA's CO\$T-AIR model to estimate the cost of installing a thermal oxidizer to reduce HAP emissions from this stream as shown in Table 1-3.

**Table 1-3.  
Control Cost-Effectiveness for the Millhouse Scrubber Exhaust**

<b>Control Option</b>	<b>Estimated HAP Reduction (tpy)<sup>a</sup></b>	<b>Annualized Cost</b>	<b>Cost-Effectiveness (\$/ton HAP)</b>
Thermal Oxidation	15.5	\$ 3,260,287 <sup>b</sup>	\$ 210,200
Scrubber Improvement	8.2	\$ 419,864 <sup>c</sup>	\$51,433

<sup>a</sup> Based on a 95% reduction in organic HAP emissions using thermal oxidation and a 50% incremental reduction in organic HAP emissions through improvement of scrubber performance. Scrubber improvement performance estimate based on the difficulty of scrubbing acetaldehyde using a water scrubber relative to the ability to scrub ethanol.

<sup>b</sup> Estimated using U.S. EPA's CO\$T-AIR model for thermal oxidation @ 70% heat recovery.

<sup>c</sup> ADM engineering estimate

The option of installing a thermal oxidizer is clearly not cost-effective nor is the option of upgrading the existing scrubber. While the option of making the scrubber improvements needed to meet the National Consent Decree requirement of 95% VOC control is not economically feasible or reasonable, ADM has agreed to make these improvements to reduce VOC emissions. Thus, ADM concludes that the CD's 95% VOC control efficiency requirement for this source also represents HAP BACT.

## **1.7 Alcohol Plant Process Sources**

The alcohol production process generates several non-condensable gas streams that are vented to the atmosphere. The first of these is the CO<sub>2</sub>-rich off-gas from the fermentation process. This off-gas stream is currently scrubbed in one of two parallel scrubbers to recover nearly all of the entrained ethanol for recycle back to the distillation operation. The current emissions limit for this stream is 10 lb/hr of VOC (combined limit for the two parallel scrubbers). Measurements at Columbus have shown that this off-gas contains some organic HAP (primarily acetaldehyde).

The second off-gas stream is a non-condensable gas stream from the distillation and dehydration steps in the alcohol purification process. This off-gas stream is currently scrubbed to recover alcohol for return to the distillation process before being vented to the atmosphere. The current emissions limit for this stream is 1.6 lb/hr of VOC. Measurements at the Columbus plant show that this off-gas contains some organic HAP (primarily acetaldehyde).

The National Consent Decree requires ADM to reduce VOC emissions from the alcohol plant process streams described above by a minimum of 95%. ADM plans to achieve the required emissions reduction by routing the distillation and dehydration process vent stream to the fermenter CO<sub>2</sub> scrubber inlet and at the same time, improving the efficiency of this scrubber. Following this modification and a planned expansion of the alcohol plant, ADM has proposed a combined VOC emissions limit for the two parallel CO<sub>2</sub> scrubbers of 13.5 lb/hr, which is equivalent to the sum of the current emissions limits for these sources. Based on measurements of CO<sub>2</sub> scrubber inlet VOC concentrations and distillation dehydration scrubber inlet VOC concentrations (at other ADM alcohol plants), ADM estimates that the proposed emissions limit of 13.5 lb/hr represents a VOC control efficiency in excess of the CD-required 95% reduction. Thus, this project is expected to meet the CD VOC control requirements for these streams.

Based on the proposed VOC limit of 13.5 lb/hr and an estimated HAP concentration of 50 wt%<sup>1</sup>, these sources have the potential to emit 29.6 tons per year of HAP. ADM has evaluated the feasibility and effectiveness of applying a thermal oxidizer downstream of the CO<sub>2</sub> scrubbers. The results of this analysis are shown in Table 1-4. As this table shows, the addition of a thermal oxidizer results in reducing organic HAP emissions by 28.1 tons per year at a cost-effectiveness of about \$21,377 per ton. This additional control also comes with a substantial energy penalty requiring the combustion of about 90 million cubic feet of natural gas annually with attendant emissions from the combustion process. This cost of control is not economically feasible and therefore, ADM concludes that HAP BACT for these sources is use of the existing scrubber to achieve either a HAP control efficiency of 65%, or a HAP exhaust concentration less than 20 ppmvd or less.

**Table 1-4. Control Cost-Effectiveness for CO<sub>2</sub> Scrubber Exhaust Stream**

<b>Control Option</b>	<b>Estimated HAP Reduction (tpy)<sup>a</sup></b>	<b>Annualized Cost</b>	<b>Cost-Effectiveness (\$/ton HAP)</b>
Thermal Oxidation	28.1	\$601,459 <sup>b</sup>	\$21,377
Scrubber Improvements <sup>2</sup>	n/a <sup>c</sup>	n/a <sup>c</sup>	n/a <sup>c</sup>

<sup>a</sup> Based on a 95% reduction in organic HAP emissions using thermal oxidation.

<sup>b</sup> Estimated using U.S. EPA's COST-AIR model for thermal oxidation @ 70% heat recovery.

<sup>c</sup> Not applicable.

HAP BACT analysis for the gluten and germ coolers are discussed in Appendix B (HAP-BACT Analysis for Ethanol Plant Expansion).

## **1.8 Germ and Gluten Dryers**

The corn milling operations at the Columbus plant produce dry germ and gluten that are shipped off-site in trucks and rail cars. Two direct fired flash dryers are used to dry gluten feed and four steam-heated dryers are used to dry corn germ. Through testing, ADM has determined that both VOC and organic HAP are vaporized in these drying processes. Currently, these emissions are controlled by existing wet scrubbers.

Pursuant to the National Consent Decree, ADM has agreed to control VOC emissions from Germ Dryers 1, 2 and 3 by 95%. These are rotary steam tube dryers that are exhausted through a common scrubber and stack. VOC emissions from the existing fourth germ dryer (a direct-fired fluidized bed dryer) and the two direct-fired gluten flash dryers were determined to be low enough that no additional control was required pursuant to the National Consent Decree. The existing fluid bed germ dryer is not equipped with a scrubber, while Germ Dryers 1-3 and the two flash dryers are equipped with impactation scrubbers for particulate control.

<sup>1</sup> The organic HAP concentration of these streams is estimated from analysis of samples collected at Columbus in cooperation with U.S. EPA during the National Consent Decree negotiations.

<sup>2</sup> The efficiency of the existing fermentation/CO<sub>2</sub> scrubber at the Columbus plant is already quite high and ADM estimates that few if any changes will be needed to meet the proposed emissions limit once the distillation scrubber vent is rerouted to these scrubbers. For this reason, ADM does not anticipate additional HAP reductions can be attained by such scrubber improvements.

Table 1-5 contains an estimate of the current potential VOC and organic HAP emissions from each of these dryers. Note that the estimates provided for Germ Dryers 1, 2, and 3 do not account for the additional reduction in VOC emissions that is expected once the scrubber system is upgraded. Since the current inlet VOC loading to the scrubber has not been measured, the degree of additional reduction associated with the CD-required 95% control cannot be determined. Note also that the HAP emissions rates are conservative (i.e., on the high side) estimates based on the testing conducted at Columbus on these sources.<sup>1</sup>

**Table 1-5. Estimated HAP Emissions from Gluten and Germ Dryers**

Source	HAP (tpy)
Germ Dryers 1-3	10.1
Fluid Bed Germ Dryer	3.3
Gluten Flash Dryer #1	10.0
Gluten Flash Dryer #2	8.6

As discussed earlier, ADM has determined that the technically feasible control options for these types of sources are: 1) improvement of the existing scrubber systems to achieve 95% control of VOC emissions; and 2) installation of a thermal oxidation system downstream of the existing scrubber to achieve 95% reduction of the organic HAP emissions. In the case of these dryers, Option 1 is not technically feasible because of the nature of the existing scrubbers, or in the case of the existing fluid bed dryer, the absence of an existing scrubber. Therefore, for these sources ADM evaluated the cost and effectiveness of installing a new packed scrubber for HAP control as a second-tier control option.

The most effective (from an emissions control standpoint) of these options is to install an add-on thermal oxidizer. ADM has used U.S. EPA's CO\$T-AIR model to estimate the cost of installing a thermal oxidizer to reduce HAP emissions from these streams by 95%. ADM has also estimated the cost of installing new packed scrubbers to obtain 50% HAP reduction (again using U.S. EPA's CO\$T-AIR model) as shown in Table 1-6.

**Table 1-6. Control Cost Effectiveness for Germ and Gluten Dryer Exhausts**

Source	Control Option	HAP Reduced (tpy)	Annualized Cost	Cost Effectiveness (\$/ton)
Germ Dryers 1-3	Thermal Oxidation	9.6	\$542,520	\$56,699
	Packed Scrubber	5.0	\$111,925	\$22,225
Fluid Bed Germ Dryer	Thermal Oxidation	3.1	\$2,123,744	\$685,079
	Packed Scrubber	1.7	\$135,955	\$79,974
Gluten Flash Dryer #1	Thermal Oxidation	9.5	\$3,216,661	\$338,677
	Packed Scrubber	5.0	\$217,199	\$43,450
Gluten Flash Dryer #2	Thermal Oxidation	8.2	\$2,800,086	\$341,640
	Packed Scrubber	4.3	\$199,149	\$46,167

As Table 1-6 shows, none of the dryer/control option combinations evaluated has a HAP control cost-effectiveness that is feasible. In the case of Germ Dryers 1, 2, and 3, ADM has agreed to improve the VOC control efficiency of the existing scrubber to 95%. ADM concludes that this improvement

<sup>1</sup> The estimated HAP fraction is 10 wt.% of the VOC. Measured HAP fractions ranged from 0% to 7% for these streams.



represents BACT for HAP emissions from these dryers. For the existing Fluid Bed germ dryer and the Gluten Flash Dryers, no additional control is cost-reasonable. Thus, ADM concludes that BACT for these sources is continued operation of the existing sources in accordance with good air pollution control practices for minimizing emissions.

(Note that as part of the expansion project, the Fluid Bed germ dryer is being modified, and is therefore subject to PSD-BACT as well. As documented in Appendix B, ADM will be installing a new wet scrubber on the modified dryer which is determined to be HAP-BACT for the modified unit.)

## **1.9 Carbon Furnaces**

ADM operates two carbon furnaces at the Columbus plant. These furnaces fire natural gas to regenerate the activated carbon used in the purification of corn syrup products. During the regeneration step, VOC and some organic HAP are evolved. Nearly all of these compounds are oxidized in afterburners that are part of the carbon furnace operations.

Based on source testing, ADM estimates that potential HAP emissions from Carbon Furnaces #1 and #2 are 5.9 tpy and 8.3 tpy respectively. Since the carbon furnaces are already equipped with a thermal oxidation device, these HAP emission rates represent post-control emissions using the most effective technology available for control of organic HAP emissions (i.e., thermal oxidation). Therefore, ADM concludes that HAP BACT for the carbon furnaces is continued operation of the furnaces and the afterburners in accordance with good air pollution control practice for minimizing emissions.

## **1.10 Fiber Dewatering**

The fiber dewatering source is a vent (SV-43) serving the dewatering screens and associated presses and tankage involved in the wet feed dewatering operations. This source was originally permitted as part of the Millhouse ventilation system, but was relocated in 1994 and is now vented through a separate stack. As discussed previously, there are small quantities of VOC (primarily ethanol) dissolved in the water associated with the wet feed. When some of this water is removed from the feed in the fiber dewatering operation, some VOC vaporizes and is emitted to the air.

Based on testing, ADM estimates the potential VOC emissions from the fiber dewatering operation to be about 7 tons per year and the maximum organic HAP content of this VOC is estimated to be less than 10 wt.% or 0.7 tons per year.

ADM evaluated the cost-effectiveness of controlling the fiber dewatering HAP emissions using a thermal oxidizer or a packed scrubber. Table 1-7 summarizes the results of the cost-effectiveness calculations for these two options. As the values in Table 1-7 show, neither of these options represents an economically feasible means of HAP control. For this reason, ADM proposes that HAP BACT for this source be no control.

**Table 1-7. Control Cost-Effectiveness for the Fiber Dewatering Exhaust**

<b>Control Option</b>	<b>Estimated HAP Reduction (tpy)</b>	<b>Annualized Cost</b>	<b>Cost-Effectiveness (\$/ton HAP)</b>
Thermal Oxidation	0.63	\$ 361,611	\$572,207
Packed Scrubber	0.33	\$51,401	\$154,537

### 1.11 Diesel Powered Generators and Pumps

The Columbus plant has an emergency generator and two fire pumps (and two proposed fire pumps) that are powered by diesel engines. These sources are listed in Table 1-8. Although these engines operate infrequently and produce few real emissions, they are a potential source of HAP emissions. Based on available emissions factors, potential HAP emissions from the generators listed in Table 1-8 are  $6.6 \times 10^{-3}$  tpy.

**Table 1-8. Columbus Plant Emergency Diesel IC Engines**

Unit Description	Size (HP)
7.5 kW Emergency Generator	10
Fire Pump #1	235
Fire Pump #2	130
Fire Pump #3 (proposed)	375
Fire Pump #4 (proposed)	375

ADM has reviewed the RBLC clearing house and has determined that typical VOC BACT requirements include good combustion practices and limits on hours of operation. ADM proposes that the same BACT requirements be applied for HAP. Specifically ADM proposes to limit hours of operation for each of the engines listed in Table 1-8 to less than 400 hours per year and proposes to employ good combustion practices to minimize emissions from the engines.

### 1.12 HCl Receiving and Storage

The Columbus plant uses about 7 million pounds of HCl solution per year. This solution is received in railcars and unloaded into one of two adjacent storage tanks. These tanks vent to the atmosphere through a common acid gas scrubber (SV-91). ADM estimates that the controlled emissions of HCl from this operation are  $6.3 \times 10^{-4}$  tons per year. Given this low level of HAP emissions, ADM concludes that BACT for this source is no additional control.

**RE: RESPONSE SUMMARY**

**Archer Daniel Midland Company  
3000 East 8<sup>th</sup> Street  
Columbus, Nebraska**

**NDEQ Facility #39285**

To Whom It May Concern:

The Department has considered all comments received and has made a final decision to modify and issue the Construction Permit for the above referenced facility. This Permit approves the expansion of ethanol production to approximately 120 million gallons per year, and construction of two new coal-fired boilers and support equipment, one new natural gas-fired boiler, and modification of the existing gluten flash dryer #2 and the fluid bed germ dryer in accordance with regulations contained in Title 129 - Air Quality Regulations.

The decision regarding issuance of this Construction Permit may be appealed under Neb. Rev. Stat. 81-1509. This appeal shall be done in accordance with the Administrative Procedure Act, Neb. Rev. Stat. Section 84-901 to 84-920 and Title 115 - Rules of Practice and Procedure.

In preparing this summary, the Department reviewed all comments made during the public comment period from May 23, 2006, to June 21, 2006, and listed all comments in the attached Responsiveness Summary. The Responsiveness Summary consists of four sections:

**Comment #:** The comment is summarized.

**Response and Rationale:** Department's response to the comment raised and the rationale.

**Changes:** Any changes to the Permit and/or Fact Sheet are addressed.

**Applicable Regulations/Statutes:** This is a listing of regulations/statutes pertinent to the comment.

The Department appreciates the time and the conscientious efforts of all that have commented. If you have any questions, please contact Clark Smith or me at (402) 471-2189.

Sincerely,

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Shelley Kaderly  
Air Quality Division Administrator

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Date

Enclosure

**RESPONSE TO PUBLIC COMMENTS SUMMARY**  
**On the issuance of a Construction Permit for ethanol production increase and**  
**Coal-fired Boiler Project (Facility #39285)**

**Background Information:**

Archer Daniel Midland Company (ADM) submitted a revised Prevention of Significant Deterioration (PSD) Construction Permit application on August 4, 2005. This permit approves the expansion of ethanol production to approximately 120 million gallons per year, and construction of two new coal-fired boilers and support equipment, one new natural gas-fired boiler, and modification of the existing gluten flash dryer #2 and the fluid bed germ dryer.

During the public comment period, The Department received comments from EPA Region VII in Kansas City and from ADM. The following are the Department's responses to the comments received during the public comment period:

**COMMENT #1:**

EPA recommends that the requirements outlined in the "Truck Traffic Fugitive Control Strategy And Monitoring Plan" (Plan), submitted by ADM with their PSD application, be stated as applicable requirements in the permit.

**RESPONSE AND RATIONALE:**

Condition XIII.(O)(1)(a) of the draft permit required ADM to develop, maintain, and implement a Plan, however the permit did not specifically address the minimum requirements of the Plan. The requirements outlined in the Plan submitted with the original PSD application include three items:

- 1) Paving facility roads that will support routine daily process traffic. The draft permit already requires that all roads be paved in Condition XIII.(O)(1).
- 2) Vacuum sweeping the facility roads three (3) times per week. Instead of a minimum vacuum sweeping frequency mandated in the permit, the Department included in the draft permit the requirement for ADM to conduct daily facility-wide dust surveys to determine when dust control measures should be implemented (Condition XIII.(O)(1)(b) ). Visible dust surveys may conclude that vacuum sweeping is required more or less frequently than three times per week. The Department, however, is not opposed to including specific requirements in the permit for ADM to vacuum sweep their roads three times per week. Note that the facility only vacuum swept their roads weekly during the development of site specific emission factors and during the time they were required to test their silt loading to demonstrate compliance with a permit limit of 1.26 grams/square meter.
- 3) Silt load testing of paved roads between the months of April and October. The Department has determined that silt testing is not necessary to demonstrate that dust emissions from the paved roads are being minimized. This is due to the permit requirement that increases the frequency of vacuum sweeping (three times per week instead of once per week) and because ADM has assumed a more conservative silt loading value of 3.0 grams/square meter when calculating potential emissions from the source. Past testing results show that with weekly vacuum sweeping, ADM has maintained silt loading values well below 3.0 grams/square meter. The requirement to vacuum sweep three times per week makes it even more likely roads will stay clean.

**CHANGES:**

Permit Conditions XIII.(O)(1)(a) was revised to specify minimum requirements for vacuum sweeping of the ADM paved roads. A corresponding discussion was updated in the Fact Sheet.

**APPLICABLE REGULATIONS:**

Title 129, Chapter 19 – Prevention of Significant Deterioration; Title 129, Chapter 32 – Duty to Prevent Escape of Dust.

**RESPONSE TO PUBLIC COMMENTS SUMMARY**  
**On the issuance of a Construction Permit for ethanol production increase and**  
**Coal-fired Boiler Project (Facility #39285)**

**COMMENT #2:**

The August 2003 consent decree requires a minimum VOC control efficiency of 95% or an outlet concentration of less than or equal to 20 ppmvd for the fermentation and distillation operations. Although the VOC emission limit in the draft permit of 13.5 lb/hr represents greater than 95% control, this limit should be clearly stated in the permit as a percent control or a maximum ppmvd value.

**RESPONSE AND RATIONALE:**

The Department agrees and in addition to the lb/hr VOC emission limit, will include the minimum percent control and maximum ppmvd value in the permit.

**CHANGES:**

Permit Condition XIII.(F)(4) was revised to include minimum VOC control efficiency and maximum ppmvd value.

**APPLICABLE REGULATIONS:**

Title 129, Chapter 19 – Prevention of Significant Deterioration; Consent Decree (United States v. ADM, No. 03-CV-2066 (C.D. Illinois))

**COMMENT #3:**

The final comment from EPA references a memorandum dated June 15, 2006, from Richard Daye to Pat Scott. This memo identifies comments pertaining to the air quality modeling protocol. The comments are summarized as follows:

- 1) Particulate matter (PM<sub>10</sub>) emissions from haul roads should be modeled as stated in the ADM modeling protocol section 3.0, submitted July 2005. Best management practices (BMP) to minimize emissions from the haul roads should be included in the permit.
- 2) Emission points SV9 and SV17 were not modeled as stated in modeling protocol sections 5.4 and 5.6.
- 3) Carbon monoxide (CO) data from air monitors located in Nebraska should be used for CO background concentrations.
- 4) More details should be provided for impact on soils, vegetation, wildlife, and visibility as stated in the modeling protocol section 8.0. What areas were analyzed for visibility impacts? Local areas such as the Columbus airport should be included in the evaluation.

**RESPONSE AND RATIONALE:**

- 1) The modeling protocol provides guidance when conducting air dispersion modeling in support of a PSD application. Any deviations from the protocol is discussed with the Department and identified during the review of the modeling submittal. It is the Department's policy not to include PM<sub>10</sub> emissions from haul roads in a modeling analysis for short-term (24-hour) and long-term (annual) averaging periods if BMPs are utilized to monitor and control fugitive dust emissions from paved haul roads. This policy is based primarily on the evidence that computer models often over-predict the impact of low-level emissions in the ambient air as outlined in the supporting materials to the Department's March 21, 2005, haul road policy. Over predicting the impact to the environment results in unnecessary burdens being placed upon the source to over control emissions from haul roads, based solely on a "worst-case" modeling analysis. It should be noted that the Department's policy on haul roads is not unique, as other states, even within Region 7, are following similar approaches. BMPs are included in the permit (see comment #1 and the Department's response) that require more aggressive controls than those used during the

**RESPONSE TO PUBLIC COMMENTS SUMMARY**  
**On the issuance of a Construction Permit for ethanol production increase and**  
**Coal-fired Boiler Project (Facility #39285)**

development of ADM's site-specific haul road emission factors. In addition, if it is determined through visual observations that existing BMPs identified in the permit are ineffective at minimizing emissions from the roads, The Truck Traffic Fugitive Control Strategy and Monitoring Plan must be revised to include additional BMPs. Therefore it is the Department's belief that the permit provides protection of the Nebraska Ambient Air Quality Standards (NAAQS) and PSD Increments.

- 2) Section 5.6 paragraph 2 states: "For single flued merged stacks where credit is not allowed, each unit should be modeled as a separate stack located at the same point. The exit parameters, i.e. velocity and temperature, would be the same as for the existing merged stack conditions and the volume flow rate based on an apportionment of the flow from the individual units."

It is economically more feasible for ADM to construct one large stack (SV9) and combine the exhaust streams from emission units EU5-9A, EU5-9B, and EU5-9C than to build three smaller stacks (one for each baghouse). Emission point SV9 is a merged emission point of three separate emission unit stacks (SV9, SV10, and SV11). In the Coal Boiler modeling that was reviewed by the Department in June 2006, SV9 was modeled at:

Stack Height: 65 meters  
Temperature: 305.22 Kelvin  
Diameter: 1.52 meters  
Exit Velocity: 12.43 meters/second.  
PM<sub>10</sub> Emission Rate: 2.048 pound/hour, this is the combined emission rate of baghouses SV9-SV11.

The modeling characteristics above are what the stack is to be permitted at, and are consistent with Section 5.6 paragraph 2.

In the protocol there was talk about SV17 and SV19 being merged into one stack. This ended up not being the case, since the final modeling was done with SV17 and SV19 modeled as separate emission points, due to a different design by the facility. This is the way that the facility is to be built, thus this is the way that it was modeled.

SV17 modeled at:

Stack Height: 65 m  
Temperature: 296.8889 K  
Diameter: 1.52 m  
Exit Velocity: 17.5 m/s  
PM<sub>10</sub> Emission Rate: 1.25 lb/hr

SV19 modeled at:

Stack Height: 35.17999  
Temperature: 296.9 K  
Diameter: 1.52 m  
Exit Velocity: 9.89 m/s  
PM<sub>10</sub> Emission Rate: 1.579392 lb/hr

- 3) The background concentration value for CO is only required when a refined (Tier 2) modeling analysis is conducted (it is added to the Tier 2 modeling results to obtain a "total" concentration). Since Tier 1 CO modeling concluded that ADM's project would not result in a significant impact to ambient levels of CO, a Tier 2 analysis was not required.

The significance levels for CO are:

1-hour averaging period concentration: 2,000 ug/m<sup>3</sup>  
8-hour averaging period concentration: 500 ug/m<sup>3</sup>

**RESPONSE TO PUBLIC COMMENTS SUMMARY**  
**On the issuance of a Construction Permit for ethanol production increase and**  
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The Tier 1 modeled worst year (2001) CO results:

1-hour averaging period concentration: 168.9 ug/m<sup>3</sup>

8-hour averaging period concentration: 69.5 ug/m<sup>3</sup>

- 4) The modeling protocol referenced in this comment did not provide the results of the additional impacts analysis. A detailed analysis was included in the PSD application (Section 8) and final modeling report (Section 10) submitted to the Department in April 2006. This analysis included:
1. Growth Impact Analysis
  2. Effects on Soil
    - a. Soil Characteristics and Geology
    - b. Pollutant Impacts on Soil
  3. Effects on Vegetation
    - a. Vegetation Survey
    - b. Pollutant Impacts on Vegetation

In 40 CFR 50 to 51, Appendix W, it states that visibility analysis is only required for Federal Class I Areas. Since the nearest Federal Class I Area is 400 km away from ADM, this was not deemed necessary. However, ADM did look at visibility impacts for Federal Class II Park and Recreational Areas within 100 km. It is currently not the Department's policy to specifically look at visibility impacts on airports, shopping centers, or other small businesses.

Visibility analysis was done out to a distance of 100km from the facility which includes the sensitive areas of:

1. Fremont Lakes State Recreation Area, 65 km east of Columbus
2. Pawnee Lake State Recreation Area, 78 km southeast
3. Branched Oak State Recreation Area, 65 km southeast
4. North Loup State Recreation Area, 92 km west
5. Willow Creek State Recreation Area, 79 km north
6. Dead Timber State Recreation Area, 65 km northeast
7. Pioneer State Recreation Area, 74 km southeast
8. Two Rivers State Recreation Area, 85 km southeast

**CHANGES:**

None

**APPLICABLE REGULATIONS:**

Title 129, Chapter 19 – Prevention of Significant Deterioration

**COMMENT #4:**

ADM requests clarification in permit conditions XIII.(F)(4)(b) and (c) that the scrubbers must meet either 65% control efficiency for HAPs or have an outlet concentration of 20 ppmvd or less. The underlying requirement is correctly indicated in Condition XIII.(F)(4), but is not repeated in later permit conditions.

**RESPONSE AND RATIONALE:**

The Department agrees that the referenced changes should be made to clarify the permit requirements that the scrubbers only need to meet one or the other requirement.

**RESPONSE TO PUBLIC COMMENTS SUMMARY**  
**On the issuance of a Construction Permit for ethanol production increase and**  
**Coal-fired Boiler Project (Facility #39285)**

**CHANGES:**

Permit Conditions XIII.(F)(4)(b) & (c) were revised by adding “or 20 ppmvd” to each condition.

**APPLICABLE REGULATIONS:**

Title 129, Chapter 27 – Hazardous Air Pollutants, Maximum Achievable Control Technology (MACT).

**SUMMARY OF ADDITIONAL CHANGES**

Condition XIII.(A)(4), Table 2: PM emission limits were reduced for emission points SV-4 (reduced from 0.87 lb/hr to 0.52 lb/hr), SV-71 (reduced from 1.37 to 0.82), SV-105 (reduced from 0.64 to 0.39), and SV-106 (reduced from 1.37 to 0.90) due to air quality dispersion modeling conducted for ADM’s dry mill project currently being reviewed by the Department. Potential emissions from these emission points was also updated in the Fact Sheet calculations, Appendix A.

Condition XIII.(E)(4), Table 8: The PM emission limit was reduced from 2.58 lb/hr to 1.55 lb/hr for emission point SV-12 due to air quality dispersion modeling conducted for ADM’s dry mill project currently being reviewed by the Department. Potential emissions from this emission point was also updated in the Fact Sheet calculations, Appendix A.

**Questions regarding this summary may be directed to:**

Air Quality Division-Permitting Section  
Nebraska Department of Environmental Quality  
PO Box 98922  
Lincoln, NE 68509-8922



## PUBLIC NOTICE

### Nebraska Department of Environmental Quality

#### Air Quality Division

Notice is given to the public, according to Chapter 14 of Title 129 - Nebraska Air Quality Regulations, of the application of Archer Daniels Midland Company (ADM) for permission to modify an existing wet corn milling and ethanol production facility (SIC 2869) located at 3000 East 8th Street in Columbus, Nebraska.

The change in potential emissions of air contaminants anticipated due to the proposed modification is estimated in the following table:

Regulated Pollutant	Change in Potential Emissions (tons/year)
Particulate Matter (PM)	173
PM smaller than or equal to 10 microns (PM <sub>10</sub> )	96
Oxides of Sulfur (SO <sub>x</sub> )	722
Oxides of Nitrogen (NO <sub>x</sub> )	578
Carbon Monoxide (CO)	740
Volatile Organic Compounds (VOC)	(-368)
Sulfuric Acid (H <sub>2</sub> SO <sub>4</sub> )	67.3
Hazardous Air Pollutants (HAP):	
Hexane (CAS# 110543)	2.42
Hydrochloric Acid (CAS# 7647010)	134.6
Hydrofluoric Acid (CAS# 7664393)	8.07
Lead Compounds	1.34
Total HAPs	150.2

Platte County is in attainment with the National Ambient Air Quality Standards (NAAQS) for all regulated pollutants and is expected to continue to be in attainment. Platte County is in compliance with the state Total Reduced Sulfur (TRS) standards and no TRS emissions are expected from this project. No impact is anticipated on habitat for any rare or threatened species.

The Department proposes to issue a Prevention of Significant Deterioration (PSD) construction permit with specific conditions, based on Title 129 - Nebraska Air Quality Regulations, which:

- Limit fuel types used in each combustion unit;
- Require the use of PM, PM<sub>10</sub>, CO, SO<sub>2</sub>, VOC and HAP control equipment;
- Limit PM, PM<sub>10</sub>, NO<sub>x</sub>, CO, SO<sub>2</sub>, H<sub>2</sub>SO<sub>4</sub>, HCl, HF, Pb, and VOC emissions from major emission units;
- Specify 5 New Source Performance Standards (Subparts Db, DD, Kb, VV, Y) requirements;
- Specify 2 National Emissions Standards for Hazardous Air Pollutants (Subparts DDDDD and FFFF);
- Specify testing requirements to demonstrate compliance on specific equipment;
- Limit drift loss and total dissolved solids (TDS) content in cooling tower water;
- Require haul road fugitive dust controls;
- Identify inspection, operation, maintenance, and monitoring requirements;
- Specify minimum stack heights requirements;

- Require public access restriction to property; and
- Specify recordkeeping and reporting requirements.

The proposed permit and supporting materials are available for inspection at the office of the Nebraska Department of Environmental Quality, Suite 400, 1200 "N" Street, Lincoln, Nebraska 68508. These materials were also forwarded to the Columbus Public Library. Telephone inquiries may be made at (402) 471-2189. Please notify the Department of Environmental Quality if alternate formats of materials are needed. Contact phone number is (402) 471-2186. TDD users please call 711 and ask the relay operator to call us at (402) 471-2186. Persons requiring further information should contact:

W. Clark Smith-Permitting Section Supervisor  
Air Quality Division  
Nebraska Department of Environmental Quality  
PO Box 98922  
Lincoln, NE 68509-8922

Within 30 days after the initial publication of this notice, persons may request or petition the Director for public hearing, or submit comments relative to the issuance of the proposed permit. Comments received during the 30 day public notice period, ending June 21, 2006, will be considered prior to the final decision to issue or to deny the proposed permit. A request or petition for hearing must state the nature of the issues to be raised and all arguments and factual grounds supporting such position. If a public hearing is granted by the Director, the hearing will be advertised by public notice at least 30 days prior to its occurrence. Comments and requests should be mailed to:

W. Clark Smith-Permitting Section Supervisor  
Air Quality Division  
Nebraska Department of Environmental Quality  
PO Box 98922  
Lincoln, NE 68509-8922